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Study on Heavy Oil Desulphurization in the Petroleum Refining Industry

MHG International Ltd.

(FINAL ISSUE)

STUDY ON FUEL OIL DESULFURIZATION IN THE PETROLEUM INDUSTRY

FOR

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ABSTRACT

The effect of desulfurization of light and heavy fuel oils on the Canadian oil refinery while maintaining 1979 product slates and all other product specifications was studied using a MHG refinery model.

The annual reduction of sulfur of fuels caused by the possible changes to low sulfur fuel specifications was evaluated.

Capital investment and operating costs required to meet three different levels of sulfur control were estimated for each region and for Canada.

RESUME

FOREWORD

This report has been prepared for Environment Canada in order to assist in the assessment of the effect of more stringent sulphur regulations for fuel oils upon the petroleum refining industry.

During 1979, Canadian refineries processed approximately 650 million barrels of crude oil containing about 900,000 tons of sulphur. Approximately 200,000 tons were recovered as elemental sulphur by means of various processing units in the refineries, however, the remaining 700,000 tons of sulphur were emitted to the atmosphere after combustion of the petroleum products. Any attempt to reduce the quantity emitted to the atmosphere involves further desulphurization being done in the refineries.

The study investigated the separate effects of reducing the sulphur content in both light and heavy fuel oils and also a combination of the two.

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1. SUMMARY AND CONCLUSIONS

The summary for Canada and conclusions of this study can be drawn as follows:

BASIS: 1979 Data and Cost

(i) Annual reduction of sulfur due to 0.3 wt. % S max. in LFO specification = 36,686 t

(ii) Annual reduction of sulfur due to 1.0 wt. % S max. in HFO specification = 256,402 t

(iii) Annual reduction of sulfur due to 0.5 wt. % S max. in HFO specification = 349,886 t

(iv) The impact of imposing specification mentioned in (ii) or (iii) reduces 41,119 t of No. 2 fuel oil and lighter.

(v) Resid hydrodesulfurization units and their supporting plants will be required to achieve the proposed low sulfur fuel specifications.

(vi) Capital investment costs for (v):

= $1.618 billions (1.0 wt. % S max. in HFO)
= $2.131 billions (0.5 wt. % S max. in HFO)
No capital investments would be required to achieve 0.3 wt. % S max. in LFO spec.

SUMMARY AND CONCLUSIONS (Cont'd)

(vii) The increased annual crude oil requirements, i.e. (viii) + (ix):

1,087,926	Bbl	(0.3 wt. % S max. in LFO)
7,178,829	Bbl	(1.0 wt. % S max. in HFO)
12,980,722	Bbl	(0.5 wt. % S max. in HFO)

(viii) The increased annual crude feed requirements due to desulfurization to meet the low S fuel specifications:

669,175	Bbl	(0.3 wt. % S max. in LFO)
1,607,125	Bbl	(1.0 wt. % S max. in HFO)
4,375,475	Bbl	(0.5 wt. % S max. in HFO)

(ix) The increased annual energy requirements, including those orginated from Fuel, Electricity and Steam:

$2,415,879 \times 10^6$	BTU	(0.3 wt. % S max. in LFO)
$32,349,014 \times 10^6$	BTU	(1.0 wt. % S max. in HFO)
$49,894,887 \times 10^6$	BTU	(0.5 wt. % S max. in HFO)

or in terms of crude oil equivalent barrels:

418,751	Bbl	(0.3 wt. % S max. in LFO)
5,571,704	Bbl	(1.0 wt. % S max. in HFO)
8,605,247	Bbl	(0.5 wt. % S max. in HFO)

(x) The increased annual cost of operating materials, including Energy, Cooling Water, Catalyst and Chemicals:

$ 6.70 millions	(0.3 wt. % S max. in LFO)
$131.95 millions	(1.0 wt. % S max. in HFO)
$209.15 millions	(0.5 wt. % S max. in HFO)

SUMMARY AND CONCLUSIONS (Cont'd)

(xi) The increased annual capital and operating costs:

$ 20.32 millions	(0.3 wt. % S max. in LFO)
$599.87 millions	(1.0 wt. % S max. in HFO)
$865.22 millions	(0.5 wt. % S max. in HFO)

or if the incremental costs of energy are represented by their crude oil equivalent costs, the increased annual capital and operating costs are:

$ 21.93	(0.3 wt. % S max. in LFO)
$601.81	(1.0 wt. % S max. in HFO)
$866.29	(0.5 wt. % S max. in HFO)

(xii) The increased operating cost per barrel of crude:

$0.032 /Bbl	(0.3 wt. % S max. in LFO)
$0.942 /Bbl	(1.0 wt. % S max. in HFO)
$1.353 /Bbl	(0.5 wt. % S max. in HFO)

or similarly, if the incremental costs of energy are represented by their crude oil equivalent costs, the increased operating cost per barrel of crude :

$0.034 /Bbl	(0.3 wt. % S max. in LFO)
$0.948 /Bbl	(1.0 wt. % S max. in HFO)
$1.355 /Bbl	(0.5 wt. % S max. in HFO)

2. BASIS OF STUDY

2.1 DESCRIPTION OF COMPUTER MODEL

A MHG computer model designed to represent a composite refinery for Canada has been used for the study. The model is the same one which has recently been developed for Environment Canada "Refinery Construction Cost Study".*

The model is a process simulator, Figure 2.1.1, and provides for material balance and product property calculation. It includes the following major refinery processes: crude/vacuum distillation, catalytic reforming, catalytic cracking and polymerization, isomerization, alkylation, gas recovery, distillate and gas oil hydrotreating and product blending. The capacities of these units installed in each refinery as of the end of 1979 were obtained from EMR Canada publication (Ref. 1).

The assumptions made for the model have been discussed in details elsewhere.* A brief description is included as follows:

(a) Crude/Vacuum Distillation

These units provides the following cuts:

	TBP End Point
Crude Tower Overhead/LSR	140 - 210°F
Naphtha	300 - 400°F
Kerosene	480 - 550°F
Light Gas Oil	600 - 700°F
Heavy Vacuum Gas Oil	900 - 1050°F
Residuum	- - -

* Environment Canada DSS File No. 37SS.KE 204-0-0510

The end points are allowed to vary within the given ranges as required to meet product specs. For example, a minimum LSR end point of 140°F was assumed. This assumption is important since it sets the minimum amount of LSR (with a low RON 68-73) that can be routed to the gasoline pool.

The yield data of the following units, i.e., (b), (c) excluding catalytic polymerization and (d) were taken from "Petroleum Refining Technology and Economics" (Reference 2). In general, these correlations are based on feedstock gravity and appropriate characterization factors which were derived from the crude assay data.

(b) Catalytic Reforming

The 1979 installed capacity as reported (Reference 1) was assumed to be referred to 98 RON. The process unit type was assumed to be semi-regenerative and mono-metallic platinum catalyst was assumed to be used.

(c) Catalytic Cracking and Polymerization

A FCC unit using zeolite catalyst and heavy vacuum gas oil feedstock were assumed for catalytic cracking. Catalytic cracker and Polymerization yields and product quality were predicted as a function of the gravity of the cracker feedstock and severity (conversion level) selected for each particular case. The correlation used is based on in-house data from wax bearing type crudes and was assumed to hold for all feedstocks encountered in the study.

(d) Isomerization

The assumption that LSR (C_5-C_6) feedstock with no recycle were applicable.

(e) Alkylation

For the HF Alkylation Unit, iso-butane requirements were taken to be 1.24 volumes per volume of olefin, and iso-butane could be imported as required to react all olefins allocated to alkylation.

(f) Gas Recovery

It was assumed that Gas Plant in each composite refinery had the capability to recover 95% iso-butane for alkylation and total C_4's for blending as required from all sources (crude tower overhead, catalytic reforming, catalytic cracking).

All excess C_4 along with C_3 and lighter were assumed to be taken as refinery fuel gas.

(g) Distillate and Gas Oil Hydrotreating

Sulfur removal efficiency was assumed to be 100% for naphtha/LSR, 95% for kerosene and 90% for light Gas Oil (LGO) and light Cyclic Oil (LCO), (see also 2.6).

The function of these hydrotreaters as represented in the model was to remove sulfur only. All feed was assumed to be recovered as desulphurized product with no generation of naphtha or light ends. All the product properties, except sulfur content, were assumed to to the same as those of the feed.

Hydrogen consumption estimates were taken from Hydrocarbon Processing (August, 1980). The consumption used for the various streams in the model are as follows:-

Naphtha/LSR	: 30 SCF/BBL
Kerosene	:200 SCF/BBL
Light Gas Oil & Light Cyclic Oil	:700 SCF/BBL

However, a set of more conservative data including that specifically applicable to atmospheric and vacuum resids hydrodesulfurization had also been used in this study (see also 2.10).

(h) Gasoline Blending

The RON was assumed to be 93.6 and 97.5 for unleaded regular and premium respectively. The blend for leaded regular was assumed to have a minimum clear RON of 85. This suggests that the additional 8 - 13 RON points can be achieved by the addition of lead. Aviation gasoline is mostly alkylate and has a RON of 93. The Eastman method based on blending indices was used for octane blending.

All gasoline were blended with C_4 to achieve a RVP of 10 psia.

(i) Aviation Turbo Fuel, Distillate and Heavy Fuel Oil Blending

The following specifications are checked for each of the following products:-

Jet B (Naphtha based Turbo Fuel)	:	RVP, gravity
Jet A (Kerosene based Turbo Fuel)	:	gravity
Diesel Fuel	:	Sulfur, gravity, pour point, viscosity
LFO (#2 and #3)	:	Sulfur, gravity, pour point, viscosity
Stove Oil/Kerosene	:	Sulfur, gravity, pour point, viscosity
HFO (#4, #5 and #6)	:	Sulfur, viscosity.

(j) Other Processes

Hydrocracking The product yields and quality were assumed to be

identical to those of catalytic cracking.

Coke, Asphalt, Aromatics and Lube Oil production

These processes are not represented. However, in order to account for these products, allocations equal to the reported production rates from Statistics Canada (Reference 3) were taken from various streams in the model as follows:

Product	Stream
Naphtha Specialties	Reformate
Lube Oil	Heavy Vacuum Gas Oil
Asphalt	Vacuum Residuum
Coke	Vacuum Residuum

Visbreaking: This process was not included in the general model.

In the present study, the basic model which simulates the operations of a composite refinery, except the part of desulfurization, is practically the same as that used in the "Refinery Construction Cost Study".

The techniques used for the simulation of the desulfurization base cases and that to optimize the hydrotreaters operations in order to achieve the low sulfur fuel specifications are similar to those developed for the "Base Cases" and the optimized "Study Cases" (which are to produce a low lead and lead-free gasoline pool) in the "Refinery Construction Cost Study" , and they would not be repeated here.

Nevertheless, the flowchart for refinery simulation, Figure 2.1.2, is included here for reference.

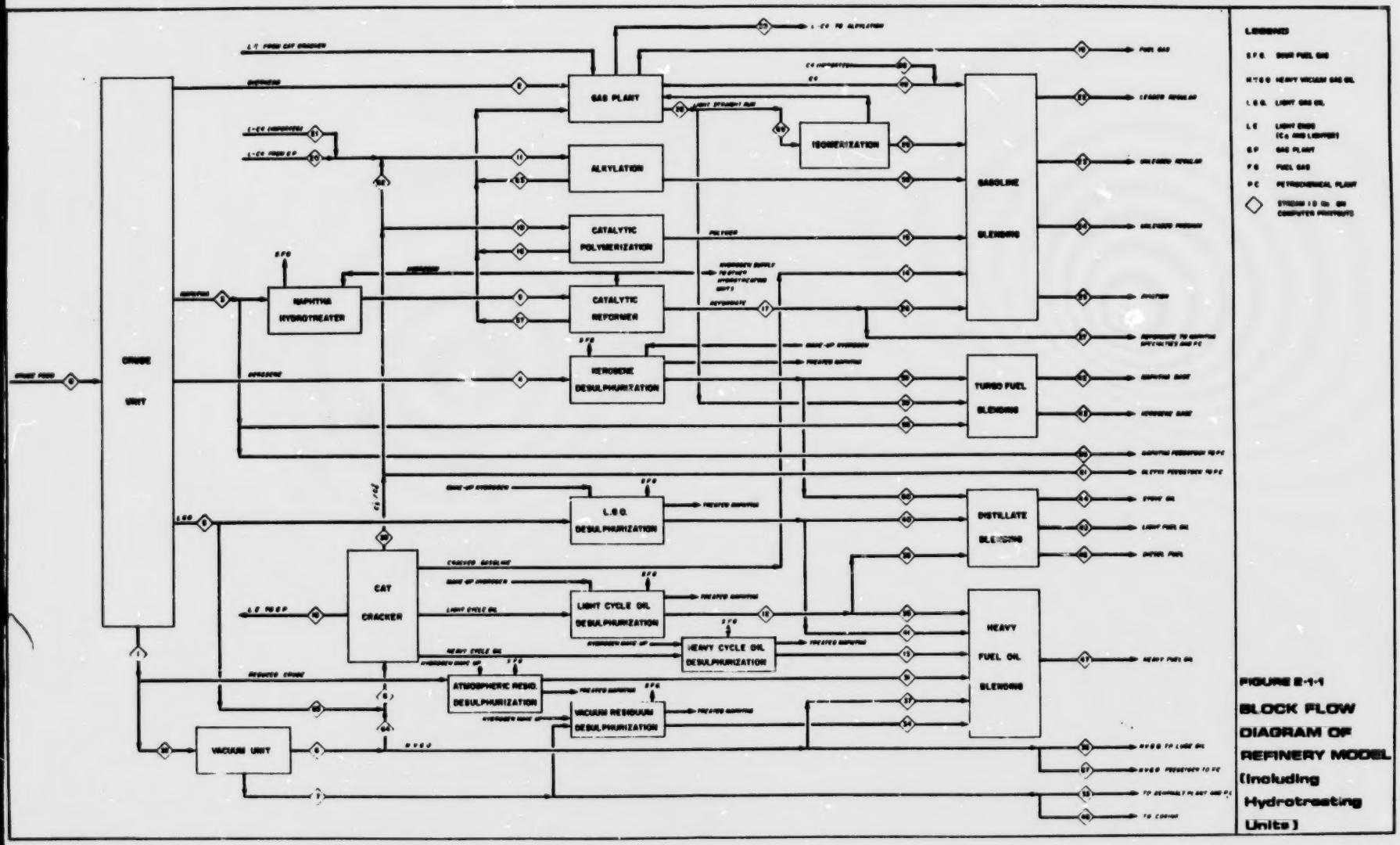
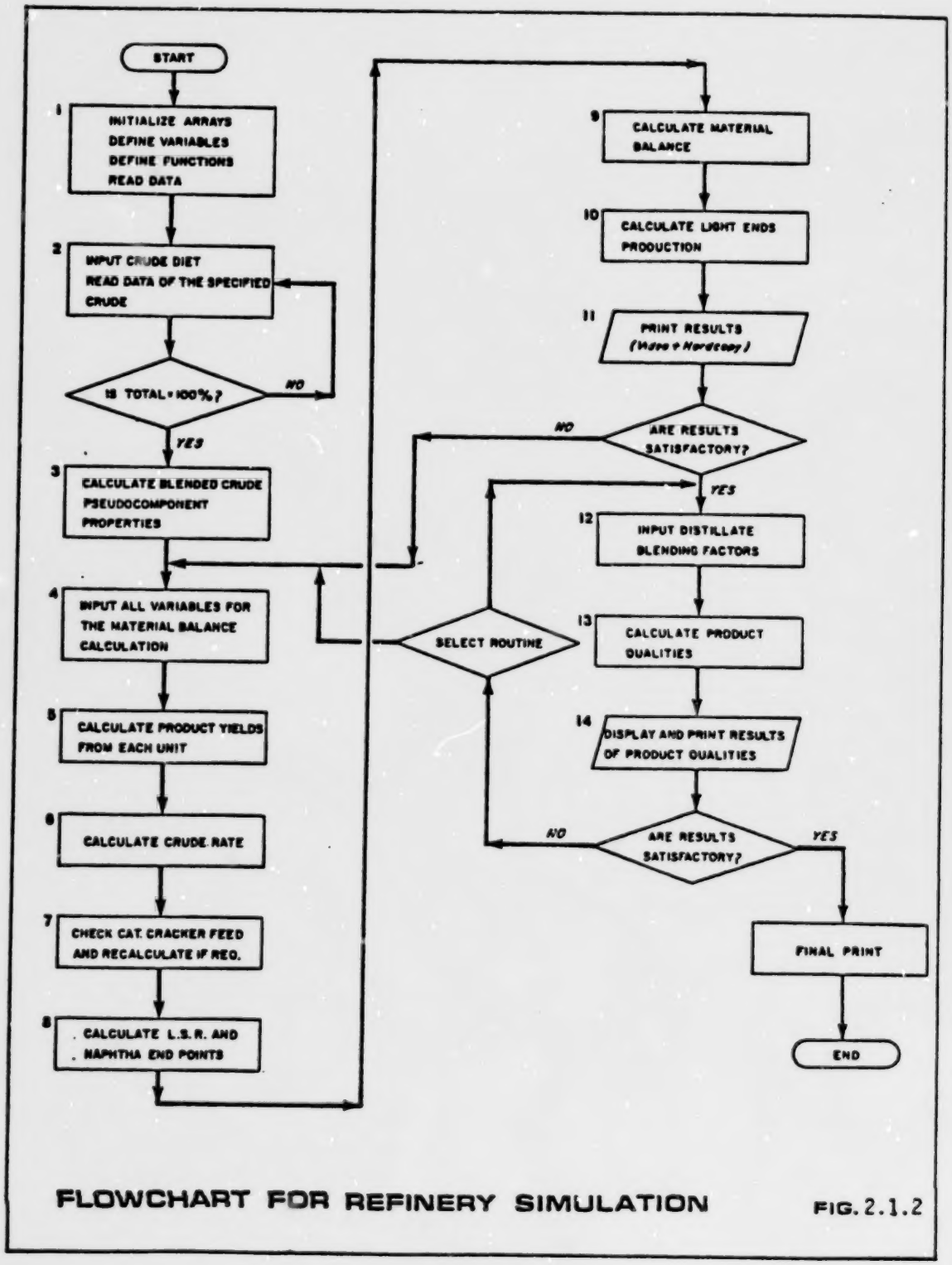


FIGURE 2-1-1

BLOCK FLOW DIAGRAM OF REFINERY MODEL (Including Hydrotreating Units)



FLOWCHART FOR REFINERY SIMULATION FIG. 2.1.2

2.2 DIVISION OF CANADA IN REGIONS

Owing to significant differences in crude oil used by refineries, it was decided to divide Canada into four geographical regions, namely Quebec, Ontario, Western and Atlantic, Figure 2.2.

For each region, the following information are presented:

- 1979 actual and simulated cases of the sulfur content of fuel oils, Tables 4.1.1, 4.2.1, 4.3.1 and 4.4.1.
- Annual reduction of sulfur due to the changes in fuel sulfur specification, Tables 4.1.2, 4.2.2., 4.3.2, and 4.4.2.
- Design capacity for additional plants required, tables 4.1.3, 4.2.3, 4.3.3. and 4.4.3.
- Increased annual crude feed requirements, Tables 4.1.4. 4.2.4, 4.3.4, and 4.4.4.
- Predicted annual change of Heavy and Light Fuel Oils due to Desulfurization, Tables 4.1.5 (a), 4.2.5 (a), 4.3.5 (a) and 4.4.5 (a).
- Prediction of annual increase of fuel gas, naphtha and sulfur due to resids desulfurization, Tables 4.1.5 (b), 4.2.5 (b), 4.3.5 (b) and 4.4.5 (b).
- Increased annual energy requirements, Tables 4.1.6, 4.2.6, 4.3.6, and 4.4.6.
- Crude oil equivalent of increased annual energy requirements, Tables 4.1.7, 4.2.7, 4.3.7 and 4.4.7.
- Estimation of capital investment, Tables 5.1.1 - 5.1.7 inclusive
- Increased annual cost of operating materials, Tables 5.2.1, 5.2.2, 5.2.3 and 5.2.4.

DEFINITION OF REGIONS IN CANADA

Fig. 2.2

- Increased annual cost of crude oil (equivalent to energy requirements), Tables 5.2.1 (a), 5.2.2. (a), 5.2.3 (a) and 5.2.4 (a).
- Cost Summary "A", Tables 5.3.1 - 5.3.4 inclusive.
- Cost Summary "B", Tables 5.4.1 - 5.4.4 inclusive.

2.3 CRUDE DIET

The 1979 crude diets used for the study have been established* and they are listed at the beginning of the computer printouts for each simulated case. Further, the sulphur content, gravity and flowrate of crude oil for each region and Canada are shown as follows:

2.3.1 Atlantic Region

Table 2.3.1 CRUDE DIET 1979

Crude Origin	LV%	°API	S (wt. %)	BPCD
Venezuela Light (Ceuta)	31.0	31.1	1.36	97,101
Venezuela Heavy (Bachaquero)	3.5	16.8	2.40	10,963
Arab Light	51.7	34.4	1.70	161,939
Arab Heavy	3.5	28.2	2.84	10,963
Iran Heavy	10.3	30.8	1.60	32,263
TOTAL	100.0			313,229
AVERAGE		31.9	1.683	

* "Refinery Construction Costs Study" for Environment Canada.

2.3.2 Quebec Region

Table 2.3.2 CRUDE DIET 1979

Crude Origin	LV%	°API	S (wt. %)	BPCD
Venezuela Light (Ceuta)	28.5	31.1	1.36	145,485
Venezuela Heavy (Bachaque)	7.3	16.8	2.40	37,254
Arab Light	10.7	34.4	1.70	54,620
Domestic Light	40.6	39.0	0.24	207,252
Condensate	2.8	63.0	0.095	14,293
Syncrude	4.4	27.7	0.08	22,461
Domestic Heavy	5.7	25.1	2.39	29,097
TOTAL	100.0			510,472
AVERAGE		33.5	1.018	

2.3.3 Ontario Region

Table 2.3.3 CRUDE DIET 1979

Crude Origin	LV%	°API	S (wt.%)	BPCD
Domestic Light	80.6	39.0	0.24	487,748
Condensate	6.5	63.0	0.095	39,334
Syncrude	6.0	27.7	0.08	36,309
Domestic Heavy	6.9	25.1	2.39	41,755
TOTAL	100.0			605,146
AVERAGE		38.8	0.335	

2.3.4 Western Region

Table 2.3.4 CRUDE DIET 1979

Crude Origin	LV%	°API	S (wt. %)	BPCD
Condensate	5.5	63.0	0.095	28,898
Syncrude	5.9	27.7	0.08	31,000
Domestic Heavy	7.5	25.1	2.39	39,406
Domestic Light	81.1	39.0	1.15	426,116
TOTAL	100.0			525,420
AVERAGE		38.5	0.934	

2.3.5 Canada

Table 2.3.5 CRUDE CONSUMPTION 1979

Region	LV %	BPCD
ATLANTIC	16.0	313,229
QUEBEC	26.1	510,472
ONTARIO	31.0	605,146
WESTERN	26.9	525,420
TOTAL	100.0	1,954,267

or 310,704 M^3/CD

2.4 PRODUCT SLATES AND SPECIFICATIONS

2.4.1 Product Slates (Tables 2.4.1.1 - 2.4.1.4)

Data reported as "Refinery Output" by Statistics Canada (Reference 3) were used as 1979 production figures for each region - Refinery Output was reported for total product, e.g. motor gasoline, rather than for each grade. The production of each grade was therefore taken to be proportional to net sales data which were also available in the same reference.

Additional information was required to estimate the relative amount of various type of petrochemical feedstocks and this was done based on the capacities of petrochemical plants as published in Oilweek (Reference 4).

TABLE 2.4.1.1

ATLANTIC REGION
TOTAL PRODUCT SLATE FOR 1979
(DESULFURIZATION BASE CASE)

PRODUCT	BPCD	VOL %
FUEL GAS (FOE) (float)	10,121	3.25
LEADED REGULAR GASOLINE	50,073	16.02
UNLEADED REGULAR GASOLINE	20,630	6.60
UNLEADED PREMIUM GASOLINE	6,619	2.12
AVIATION GASOLINE	0	0
NAPHTHA SPECIALTIES	0	0
OLEFIN PETROCHEMICAL FEED	2,416	0.77
NAPHTHA PETROCHEMICAL FEED	0	0
JET FUEL B	1,726	0.55
JET FUEL A	7,224	2.32
STOVE OIL	8,025	2.57
DIESEL FUEL	30,225	9.67
LIGHT FUEL OIL (#2)	70,698	22.62
HEAVY FUEL OIL (#6)	99,604	31.87
LUBE OIL	0	0
ASPHALT	5,125	1.64
COKE	0	0
TOTAL PRODUCT	312,486	100
CRUDE OIL FEED	313,229	100
IMPORTED i-C4	0	0

TABLE 2.4.1.2

QUEBEC REGION

TOTAL PRODUCT SLATE FOR 1979
(DESULFURIZATION BASE CASE)

PRODUCT	BPCD	VOL %
FUEL GAS (float)	18,454	3.65
LEADED REGULAR GASOLINE	85,908	17.01
UNLEADED REGULAR GASOLINE	40,288	7.98
UNLEADED PREMIUM GASOLINE	32,044	6.34
AVIATION GASOLINE	1,693	0.34
NAPHTHA SPECIALTIES	4,605	0.91
OLEFIN PETROCHEMICAL FEED	1,870	0.37
NAPHTHA PETROCHEMICAL FEED	19,500	3.86
JET FUEL B	5,130	1.02
JET FUEL A	16,469	3.26
STOVE OIL	8,085	1.60
DIESEL FUEL	49,259	9.75
LIGHT FUEL OIL (#2)	92,430	18.30
HEAVY FUEL OIL (#6)	102,480	20.29
LUBE OIL	4,378	0.87
ASPHALT	22,484	4.45
COKE	0	0
TOTAL PRODUCT	505,007	100
CRUDE OIL FEED	510,472	100
IMPORTED 1-C4	0	0

TABLE 2.4.1.3
ONTARIO REGION
TOTAL PRODUCT SLATE FOR 1979
(DESULFURIZATION BASE CASE)

PRODUCT	BPCD	VOL %
FUEL GASE (float)	24,502	4.04
LEADED REGULAR GASOLINE	138,858	22.38
UNLEADED REGULAR GASOLINE	62,423	10.28
UNLEADED PREMIUM GASOLINE	18,213	3.00
AVIATION GASOLINE	221	0.04
NAPHTHA SPECIALTIES	11,557	1.90
OLEFIN PETROCHEMICAL FEED	6,200	1.02
NAPHTHA PETROCHEMICAL FEED	53,830	8.87
JET FUEL B	3,555	0.59
JET FUEL A	18,313	3.02
STOVE OIL	4,329	0.71
DIESEL FUEL	55,060	9.07
LIGHT FUEL OIL (#2)	94,756	15.61
HEAVY FUEL OIL (#6)	102,698	16.92
LUBE OIL	7,839	1.30
ASPHALT	6,510	1.07
COKE	1,095	0.18
TOTAL PRODUCT	606,959	100
CRUDE OIL FEED	605,146	99.88
Imported i-C4	718	0.12

TABLE 2.4.1.4
WESTERN REGION
TOTAL PRODUCT SLATE FOR 1979
(DESULFURIZATION BASE CASE)

PRODUCT	BPCD	VOL %
FUEL GAS (float)	23,110	4.43
LEADED REGULAR GASOLINE	159,718	30.63
UNLEADED REGULAR GASOLINE	58,307	11.18
UNLEADED PREMIUM GASOLINE	13,350	2.56
AVIATION GASOLINE	2,635	0.51
NAPHTHA SPECIALTIES	740	0.14
OLEFIN PETROCHEMICAL FEED	0	0
NAPHTHA TETROCHEMICAL FEED	800	0.15
JET FUEL B	18,366	3.52
JET FUEL A	12,686	2.43
STOVE OIL	11,768	2.26
DIESEL FUEL	123,877	23.76
LIGHT FUEL OIL (#2)	26,869	5.15
HEAVY FUEL OIL (#6)	38,536	7.39
LUBE OIL	3,886	0.75
ASPHALT	24,489	4.70
COKE	2,250	0.44
TOTAL PRODUCT	521,387	100
CRUDE OIL FEED	525,420	100
IMPORTED i-C4	0	0

2.4.2 PRODUCT SPECIFICATIONS, Table 2.4.2

The number of product types was minimized and their specifications were derived using an average of the specifications for the range of grades of products within a particular broad category.

The specification published by the Canadian Government Standard Board were supplemented by additional data from both in-house references and major refineries themselves.

The same specifications were adopted in a recent study by Montreal Engineering Co. Ltd. for Transport Canada to assess future availability of transport fuels.

Gasoline octane numbers (RON) for the three basic grades were derived from a recent independent study on Canadian gasoline sales (Ref. 5).

TABLE 2.4.2

GENERAL PRODUCT SPECIFICATIONS 1979

Leaded Regular Gasoline		
Octane No.	RON	93.1
Lead Content	CC/IG	see regional concentration in printouts
RVP	PSIA	7.0 - 12.5
Unleaded Regular Gasoline		
Octane No.	RON	93.6
RVP	PSIA	7.0 - 12.5
Unleaded Premium Gasoline		
Octane No.	RON	97.5
RVP	PSIA	7.0 - 12.5
Aviation Gasoline		
Octane No.	RON	93.0
RVP	PSIA	10.0
Turbo Fuel Jet B (Naphtha Base)		
Specific Gravity		0.750-0.801
ASTM Distillation % 20/50/90,	^{o}F	290/370/470(max)
RVP	PSIA	2 - 3
Sulphur	Wt.%	0.4(max)

Table 2.4.2 (Cont'd)

Turbo Fuel Jet A (Kerosene Base)

Speific Gravity		0.774-.839
Pour Point, ^{o}F		-55 (max)
ASTM Distillation 10%, ^{o}F		400 (max)
Flash Point	^{o}F	90 (min)
Sulphur	wt %	0.2 (max)

Diesel Fuel

Pour Point	^{o}F	-25 (max)
Specific Gravity		.816 - 0.855
ASTM Distillation % 10/50/90,	^{o}F	460/520/625 (max)
Flash Point	^{o}F	130 (min)
Cetane Index		45 (min)
Viscosity @ 100^{o}F,	CS	1.85 - 3.95
Sulphur	wt %	0.4 (max)

Stove Oil

Pour Point	^{o}F	-35 (max)
Specific Gravity		0.784 - 0.840
ASTM Distillation % 10/50/90,	^{o}F	420/450/520 (max)
Flash Point	^{o}F	120 (min)
Viscosity @ 100^{o}F,	CS	1.25 (min)
Sulphur	wt %	0.2 (max)

Light Fuel Oil (#2)

Pour Point	^{o}F	0 (max)
Specific Gravity		0.820 - 0.887
ASTM Distillation % 10/50/90,	^{o}F	460/530/675 (max)
Flash Point	^{o}F	1.30 (min)
Viscosity @ 100^{o}F,	CS	1.75 - 4.25
Sulphur	wt %	0.5 (max)

Heavy Fuel Oil

Sulphur	wt %	3.5 (max)
Viscosity @ 122^{o}F,	CS	92 - 638

2.5 INSTALLED CAPACITY OF DISTILLATE AND GAS OIL HYDROTREATING

The installed capacity of distillate and gas oil hydrotreating units are taken from "Petroleum Refineries in Canada, December 1979" published by EMR Canada (Ref. 1).

They are listed, by region, in the following:-

TABLE 2.5

INSTALLED DISTILLATE AND GAS OIL HYDROTREATING UNIT CAPACITIES

REGION	DISTILLATE HTU BPCD	GAS OIL HTU BPCD	TOTAL BPCD
Atlantic	60,100	42,000	102,100
Quebec	151,200	10,000	161,200
Ontario	52,900	28,200	81,100
Western	58,130	57,330	115,460
Canada	322,330	137,530	459,860

2.6 SULFUR CONVERSION AND RECOVERY

In the simulation model, the desulfurization efficiency was assumed to be 95% for kerosene HTU, 90% for LGO and LCO HTU's, as mentioned in 2.1. Furthermore, for HCO, Vacuum and Atmospheric Residue HDS units, the sulfur conversion was assumed to be 85%.

Sulfur recovered in the proposed sulfur plants where the sulfur production is 100 STPD or more will have an efficiency of 99% minimum. For sulfur production rates less than 100 STPD recovery efficiency will be 97.5% minimum.

2.7 METALS CONTENT OF RESIDUAL OIL

The metals content (Fe, Ni, V, Cu) of vacuum residuum and that of atmospheric residuum are considered to be of importance when selecting the hydordesulfurization process. They have been estimated respectively according to the crude origin.

TABLE 2.7

METALS CONTENT OF RESIDS

REGION	VAC. RESID (ppm)	ATMOS. RESID (ppm)
Atlantic	325	218
Quebec	226	152
Ontario	< 20	< 10
Western	< 30	< 15

2.8 RESIDUE HYDRODESULFURIZATION PROCESS SELECTED

The recommendations from the report "Evaluation of Residual Desulfurization Processes for Petroleum Refineries" by R.S. Krishnamoorthy, August 1977, SNC/FW, Montreal, Quebec (Ref. 6), have been considered in selecting an appropriate process for resids desulfurization.

The HRI (Hydrocarbon Research Inc.) H-Oil (Ebullated Bed) process was selected for the vacuum and atmospheric resids hydrodesulfurization in this study due to its capability to process high metals content residue and its significant cost advantage over the fixed bed processes as concluded by the report mentioned in the preceding paragraph.

2.9 HYDROTREATER PRODUCT YIELDS

The desulfurized fuel oil yield of each hydrotreater in the model was assumed to be 100%, e.g. flowrate (BPCD) of feed to LGO HTU = flowrate (BPCD) of desulfurized LGO, and light ends and naphtha yield were not included.

However, in this study, the product yields of hydrotreaters, e.g. sour fuel gas, treated naphtha and desulfurized fuel oil, are all considered in the material balance of a composite refinery.

For vacuum resid HDS, product yields data from H-Oil are used (Ref. 6), Tables 2.9.2, 2.9.3. For atmospheric resid HDS and other HTU's, Table 2.9.1 in-house data are assumed to be applicable.

TABLE 2.9.1

HYDROTREATERS PRODUCT YIELDS

BASIS: 10,000 BPCD Feed

HDS UNIT	Sour Fuel Gas (incl. C_4) MMSCFD	Treated Naphtha (C_5-375°F) BPCD	Desulfurized Fuel Oil (375°F +) BPCD	Sour Water Lbs/Hr
Kerosene	0.99	30	10,020	8,100
LGO	1.24	90	10,000	22,400
LCO	1.24	107	9,860	22,400
HCO	1.50	150	9,850	12,300
* Atmos. Resid.	6.35	100	10,000	14,100

* for Atlantic Region only.

TABLE 2.9.2

VACUUM RESID. HDS
PRODUCT YIELDS

Process: H-OIL
Wt. % S in $375^{o}F^{+}$ product : 1.0
Basic: 10,000 BPCD

REGION	Sour Fuel Gas (incl. C_4) MMSCFD	Treated Naphtha (C_5 - $375^{o}F$) BPCD	Desulfurized Fuel Oil ($375^{o}F$ +) BPCD	Sour Water LBS/HR
Atlantic	5.47	747	9,640	14,100
Quebec	4.55	640	9,660	14,000
Ontario	5.47	747	9,640	14,100
Western	4.88	706	9,650	12,300

TABLE 2.9.3

VACUUM RESIDS HDS PRODUCT YIELDS

Process: H-OIL
Wt. % S in $375\ ^{o}F^{+}$ Product: 0.5
Basis: 10,000 BPCD

REGION	Sour Fuel Gas (incl. C_4) MMSCFD	Treated Naphtha (C_5 - $375^{o}F$) BPCD	Desulf. Fuel Oil ($375^{o}F^{+}$) BPCD	Sour Water
Atlantic	6.35	1,384	9,210	14,200
Quebec	5.70	859	9,530	14,200
Ontario	6.35	1,384	9,210	14,200
Western	5.90	1,176	9,350	11,950

2.10 HYDROGEN CONSUMPTION

The make-up H_2 required for vacuum residuum, HDS is based on H-OIL data reported (Ref. 6) or tabulated in Table 2.10.2.

For the H_2 consumed by other hydrotreaters and atmospheric residuum HDS, Table 2.9.1 data are assumed to be applicable.

Due to anticipated losses, H_2 supply to vacuum and/or atmospheric resids, was designed to be 120% of the actual consumption.

TABLE 2.10.1

H_2 CONSUMPTION IN HTU

HYDROTREATING/HYDRODESULFURIZATION UNIT	H_2 (100%) CONSUMPTION SCF/BBL feed
Naphtha	100
Kerosene	300
LGO	500
LCO	700
HCO	1,000
Atmos. Resid.*	1,200

* For Atlantic Region only.

TABLE 2.10.2
H_2 CONSUMPTION IN
VAC. RESID. HDS

PROCESS: H-OIL

REGION	H_2 (100 mole %) CONSUMPTION SCF/BBL	
	1.0 wt. % S in 375° F + Product	0.5 wt. % S in 375° F + Product
Atlantic	1,111	1,552
Quebec	970	1,213
Ontario	1,111	1,552
Western	970	1,300

2.11 REFINERY OWN FUEL CONSUMPTION, SALEABLE HEAVY FUEL OIL AND LIGHT FUEL OILS

"Statistics Canada - Refined Petroleum Products Dec. '79" (Ref. 3) data were used for the calculation of the followings.

2.11.1 Refinery Own Fuel Consumption

The own consumption consists mainly of heavy fuel oils (#4, #5 and #6) and relatively smaller amount of higher fuel oils (#2 and #3), diesel fuel and stove oil/kerosene; broken down for:

TABLE 2.11.1

ANNUAL REFINERY OWN FUEL CONSUMPTION

REGION	HFO Bbl (M^3)	LFO Bbl (M^3)	DIESEL FUEL Bbl (M^3)	STOVE OIL/KEROSENE Bbl (M^3)
Atlantic	1,172,251 (186,373)	27,770 (4,415)	82,667 (13,143)	1,183 (188)
Quebec	4,248,591 (675,472)	48,520 (7,714)	195,619 (31,101)	2,296 (365)
Ontario	5,639,237 (896,567)	98,731 (15,697)	164,202 (26,106)	1,648 (-262)
Western	554,585 (88,172)	3,510 (558)	73,408 (11,671)	4,309 (685)
CANADA	11,614,664 (1,846,584)	198,531 (28,384)	515,896 (82,021)	6,140 (976)

2.11.2 SALEABLE HEAVY FUEL OIL

The saleable heavy fuel oil (#4, #5 and #6) includes interprovincial, export/import of Canada and domestic sales. The annual amount was calculated by subtracting "own consumption" and "losses" from "refinery output" (as termed by Statistics Canada) and correction for inventory changes. The data used are as follows:

TABLE 2.11.2

ANNUAL SALEABLE HEAVY FUEL OIL

REGION	ANNUAL SALEABLE HEAVY FUEL OIL	
	Bbl	(M^3)
Atlantic	33,986,123	(5,403,362)
Quebec	33,876,737	(5,385,971)
Ontario	32,071,210	(5,098,915)
Western	13,039,419	(2,073,102)
CANADA	112,973,489	(17,961,350)

2.11.3 LIGHT FUEL OILS

The light fuel oil products include LFO (#2 and #3), diesel fuel oil and stove oil/kerosene. Their annual productions were calculated by subtracting "own consumption", "losses" from "refinery output" and correcting for inventory changes. The data used are as follows:

TABLE 2.11.3

ANNUAL PRODUCTION OF LIGHT FUEL OILS

REGION	LFO Bbl (M^3)	DIESEL FUEL Bbl (M^3)	STOVE OIL/KEROSENE Bbl (M^3)
Atlantic	26,147,963 (4,157,194)	10,454,446 (1,676,592)	2,826,597 (449,393)
Quebec	33,792,121 (5,372,518)	17,400,119 (2,766,398)	2,743,836 (436,235)
Ontario	32,311,575 (5,137,130)	19,619,140 (3,119,194)	1,239,728 (197,101)
Western	9,831,375 (1,560,202)	44,218,784 (7,030,225)	4,162,031 (661,710)
CANADA	102,065,034 (16,227,044)	91,783,489 (14,592,409)	10,972,192 (1,744,439)

2.12 CAPITAL INVESTMENT COSTS BASIS

The scope includes all fixed capital costs, but excludes land development costs.

Fixed Costs include:

- Battery Limit Process Units
- Site Preparation
- Industrial Buildings
- Storage Facilities
- Auxiliary Facilities
- Offsite Piping & Services

2.12.1 Basis

The capital investment costs presented within this report are based on a continuously updated extensive "MHG Cost Library" and additional data obtained from licensors and MHG affiliates.

The data from the library is classified and grouped into complete cost units which include all direct and indirect costs necessary to engineer, procure and construct all battery limit and offsite equipment and material. The grouping is with respect to equipment, material and labour components, together with associated indirect costs.

The equipment component includes the cost of major process items, such as towers, reactors, exchangers and offsite storage, utility plants and auxiliaries. The material dollar includes all necessary items for piping, instrumentation, civil, structural and electrical systems. Labour is comprised of direct field costs and construction overheads related to aforementioned equipment and material.

The indirect cost component covers services provided by engineering, procurement, field supervision, fees and the project management team.

2.12.2 Pricing Basis

The direct cost of desulfurization units selected for this study is based on 85% sulfur conversion.

The "cost vs. capacity" curve is represented by:-

$$\text{Unit Direct Cost} = \left(\frac{\text{Capacity - Study}}{\text{Capacity - Library}}\right)^{Y} \times \text{Library Cost}$$

Where the exponent Y is the scale factor. This method has worked well historically where capacit ies vary no more than three times.

The cost of offsite investment was prepared and used in this study for power plants, utility plants, auxiliary equipment, site emprovements, distribution and supply systems. On major offsite costs, such as tank farms, shipping stations, main headers and blending systems, a general scope was prepared and costed. These costs were adjusted to facilitate the unique requirements of each refinery location.

The "Unique" construction requirements of each refinery location across Canada require that the cost estimate be adjusted to the refinery location. This cost is generally labour related and includes geographical, historical, economic and climatic conditions. The adjustments have been made in the form of relative factors, backed by known, on hand cost comparisons and published statistics.

However, in several instances, and especially in the Western region, the desulphurization capacities for individual refineries are small. Consequently, the ratio of "capacity-library"/"capacity-study" in several cases are greater than three (3). (This "bottom limit" of (3) appears to be a reflection of the relative feasibility of such small plants; available historical data consists of only much larger plants.)

To fully consider these low capacities, it would be necessary to address new technologies, the possibilities of revamps at existing plants or even their reconstruction to higher capacities. This, however, may not be feasible, or as in the case of a revamp, even possible. At any rate, such discussion is beyond the scope of this study.

Consequently, it was necessary to make some adjustment to the methodology as it applies to these "bottom limit" cases. All plants whose capacities fell below the lower limit were costed at this point, while those that occurred above the lower limit had contingency factor applied to them. This adjustment is based on the assumption, that as capacity decreases, the corresponding investment density, e.g. $/Bbl, would increase.

In graphic terms this means, that the "cost vs. capacity" curves level off below the "bottom limit". Therefore, the difference in investment costs for different levels of desufurization. otherwise clearly evident in the cases of plants with higher capacities, becomes somewhat - though not incorrectly - indistinguishable in the cases of smaller plants.

Figure 2.12.6 shows the relationship of total capital investment versus heavy fuel oil production in the Quebec region, where desulfurization capacities are sufficiently large to warrant confidence in the available historical basis. A clear differential increase in investment costs with respect to the two levels of desulfurization becomes apparent.

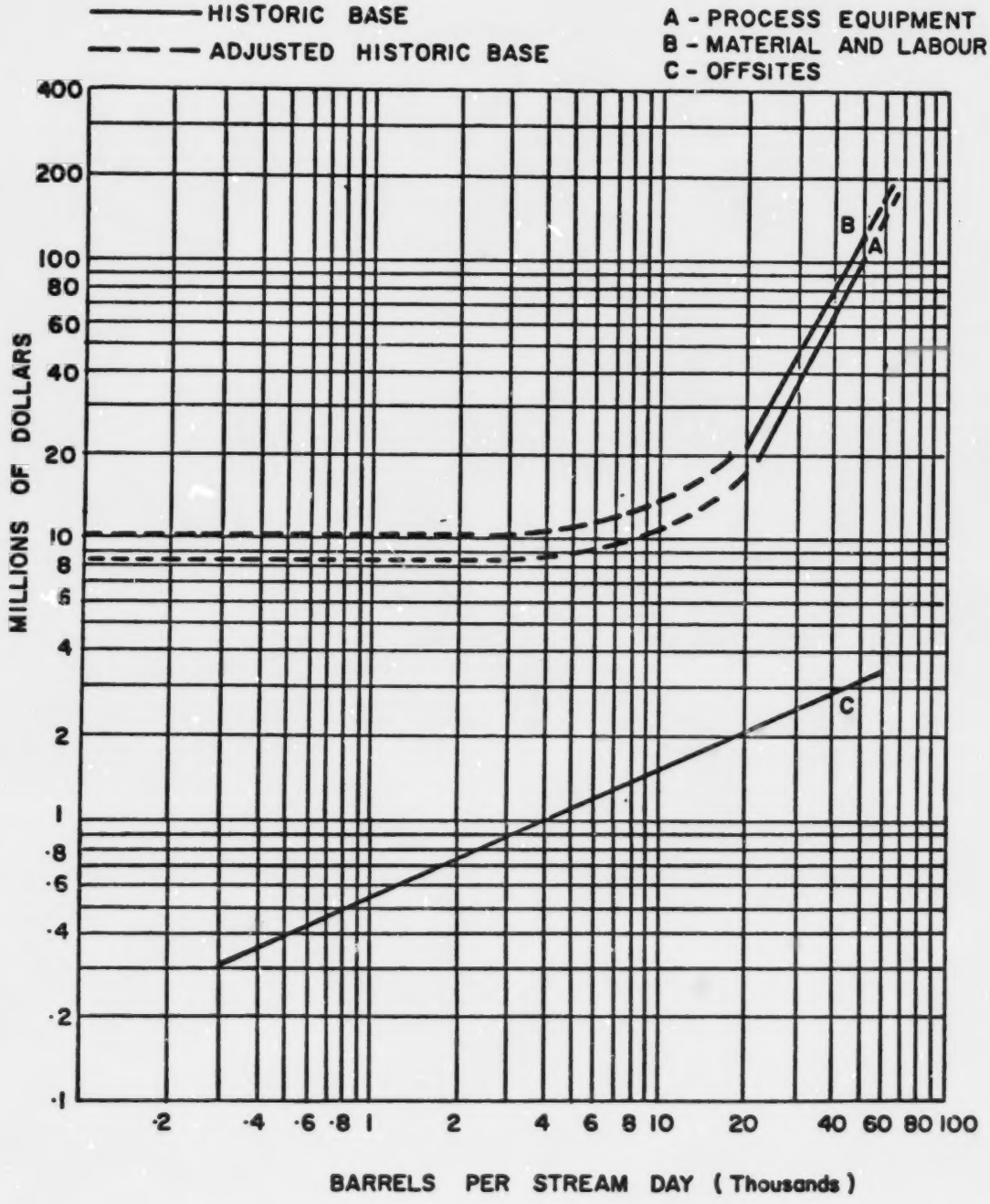
The "direct cost vs. capacity" curves, for hydrodesulfurization and supporting plants, used for this study are shown in Figures 2.12.1 to 2.15.5 inclusive.

It is important to realize, that the direct cost curves presented are only representative of historical data, normalized to 4th quarter '79, Ontario location basis, for battery limit (equipment and labour) and offsite (including utilities) costs. When dealing with a specific refinery at other region, the cost data obtained from these curves are modified by appropriate "regional adjustment factors".

As well, the costs of initial "Catalyst", Tables 5.1.1.3 (a) to (e), 5.1.2.3 (a) to (g), 5.1.3.3 (a) to (h), 5.1.4.3, (a) to (p), are obtained from licensors and applied in a factorial fashion. The costs of "H.O. Engineering", Tables 5.1.1.3 (a) to (e), 5.1.2.3 (a) to (g), 5.1.3.3 (a) to (h) and 5.1.4.3 (a) to (p), computed as a percentage of the sum of battery limit and offsite costs.

Further, the capital cost of each desulfurization and supporting plants, Tables 5.1.1.1, 5.1.1.2, 5.1.2.1, 5.1.2.2, 5.1.3.1, 5.1.3.2, 5.1.4.1, 5.1.4.2, 6.12 (a) and 6.12 (b), includes costs of initial catalyst and home office engineering.

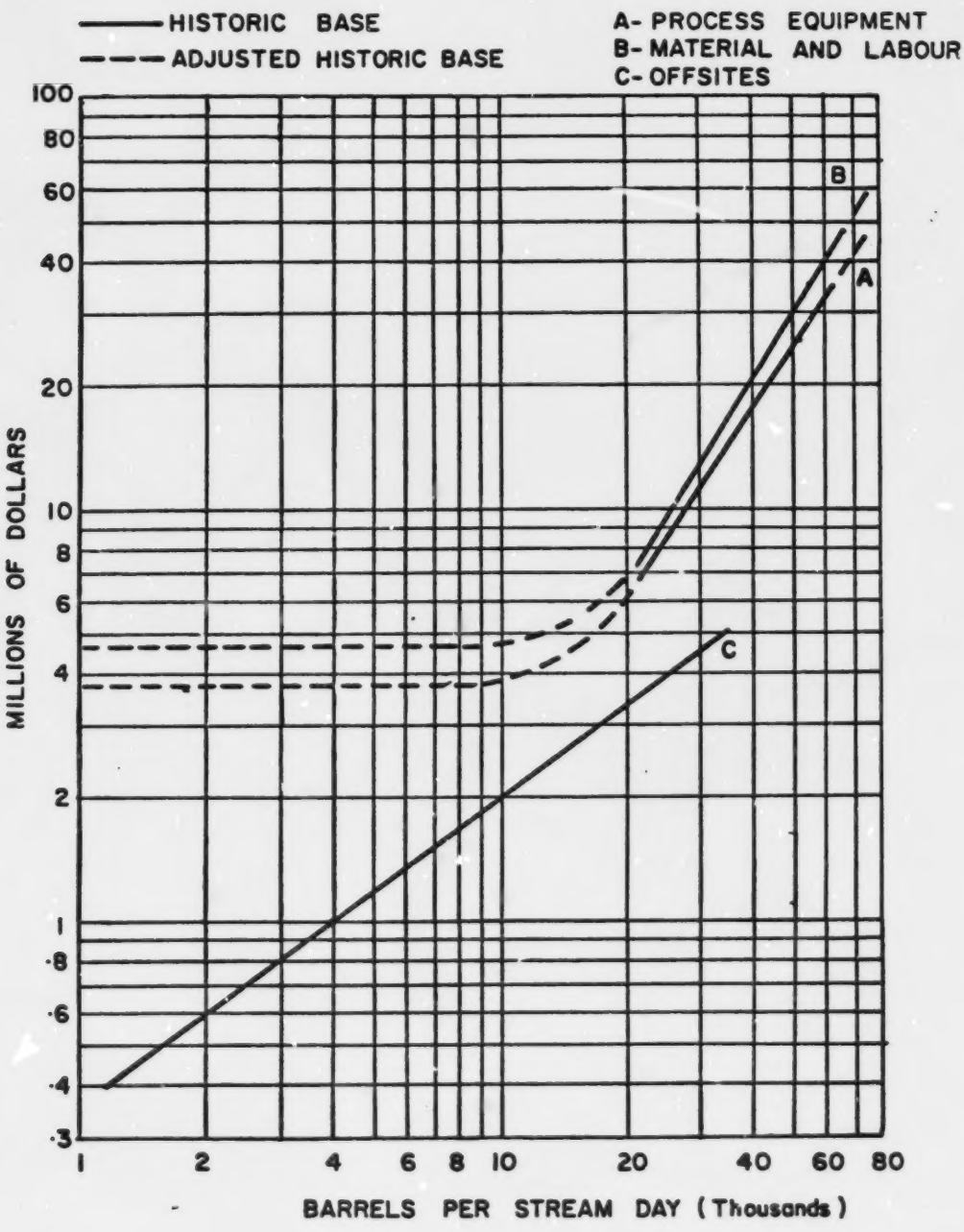
FOURTH QUARTER '79, TORONTO, ONTARIO BASE



DIRECT COST FOR VACUUM RESIDUAL HDS

FIGURE 2·12·1

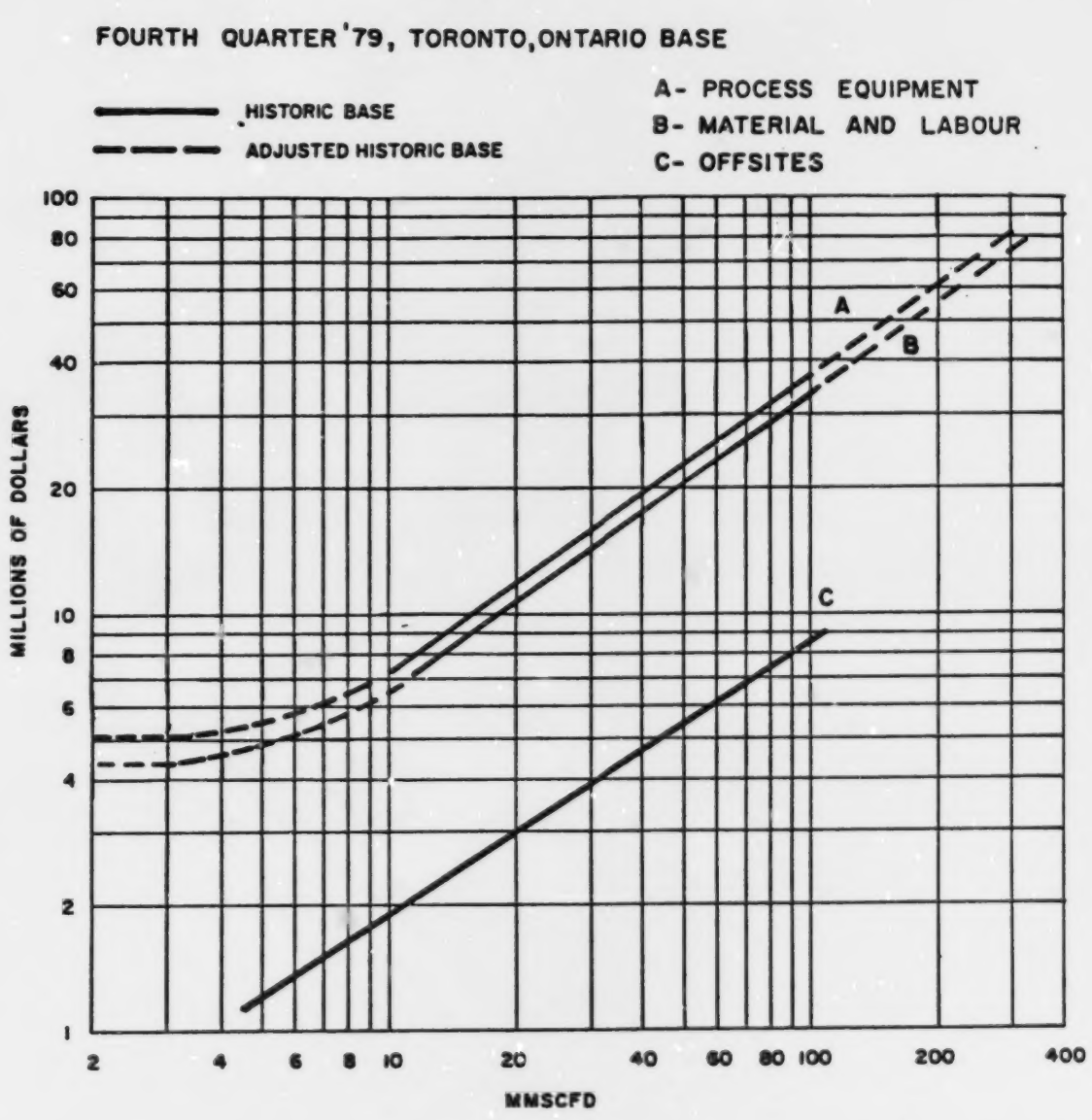
FOURTH QUARTER '79, TORONTO, ONTARIO BASE



DIRECT COST FOR

ATMOSPHERIC RESIDUAL HDS

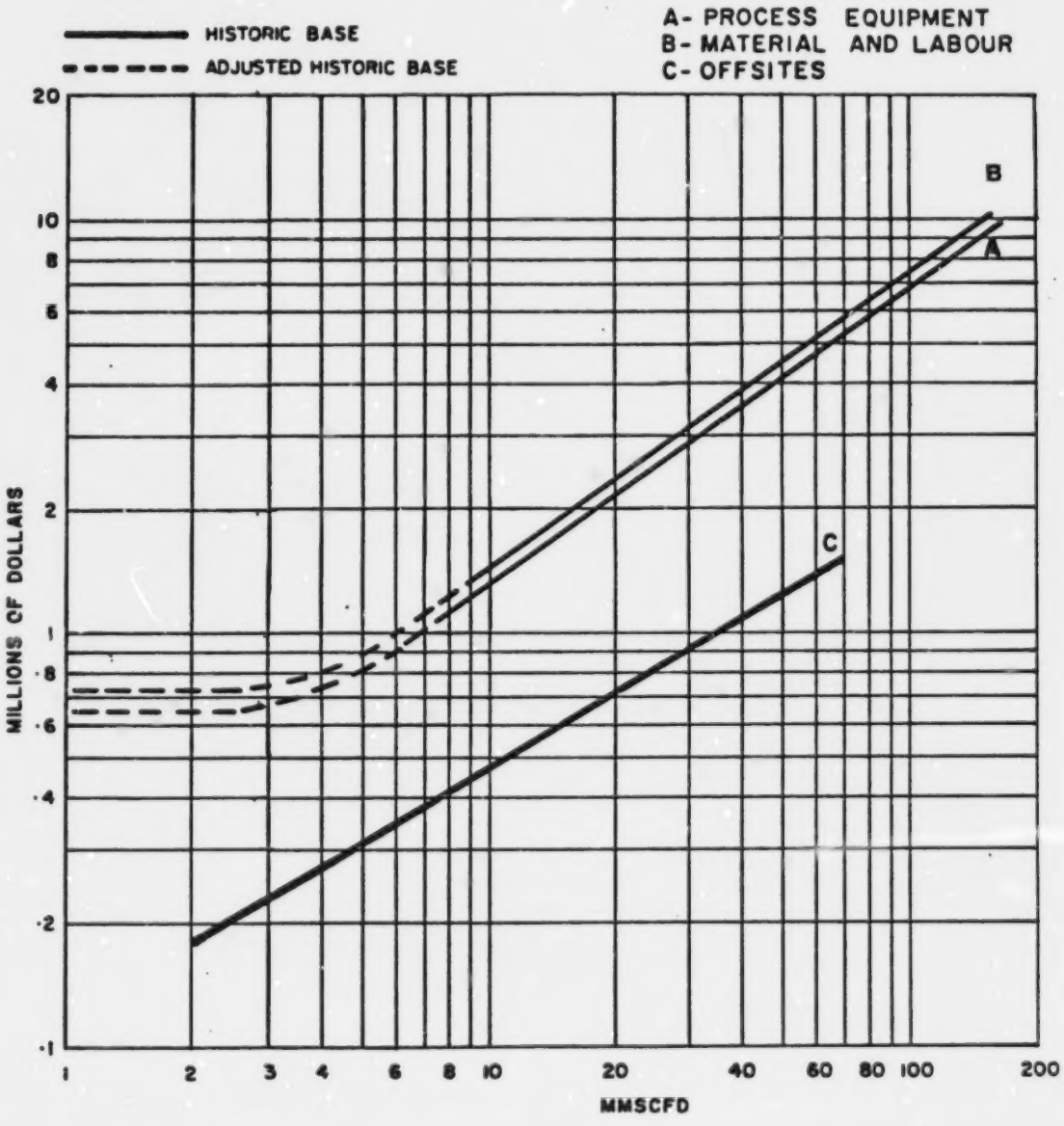
FIGURE 2·12·2



DIRECT COST FOR HYDROGEN PLANTS FROM NAPHTHA FEEDSTOCK

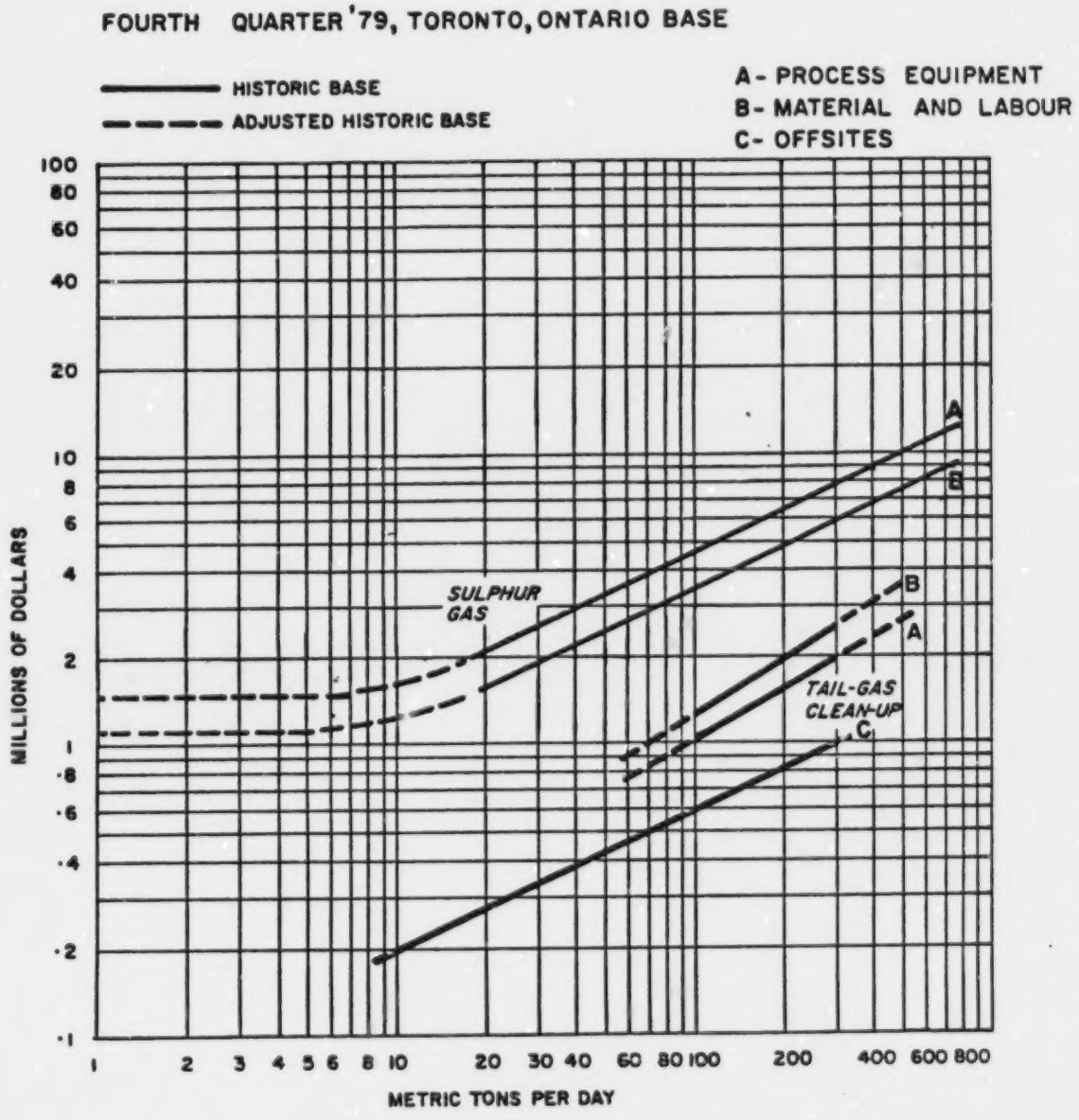
FIGURE 2·12·3

FOURTH QUARTER '79, TORONTO, ONTARIO BASE



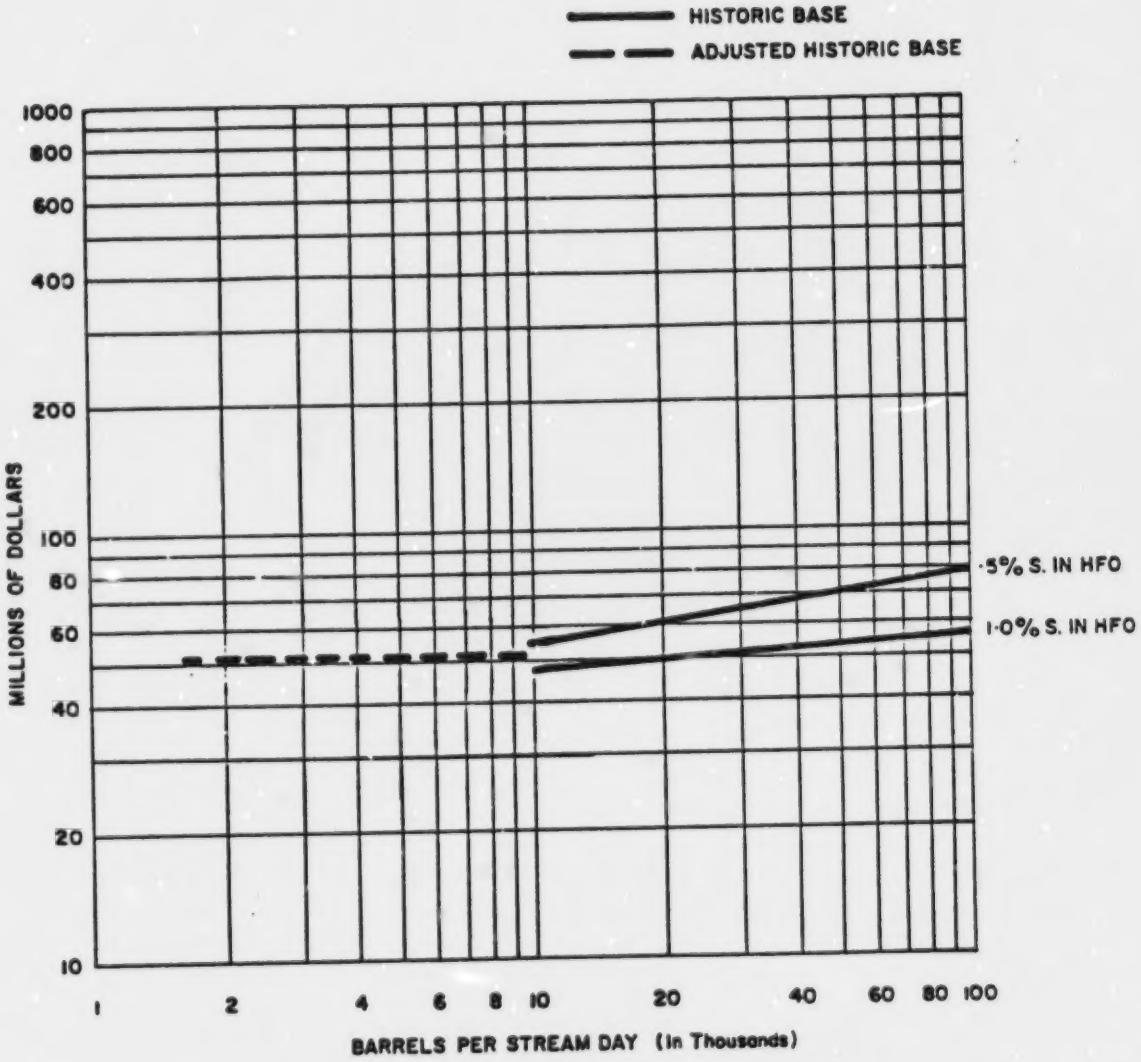
DIRECT COST FOR AMINE PLANTS

FIGURE 2·12·4



DIRECT COST FOR SULPHUR RECOVERY PLANTS

FIGURE 2·12·5



TOTAL CAPITAL INVESTMENT vs HFO PRODUCTION (Quebec Region) IN TWO LEVELS OF DESULPHURIZATION

FIGURE 2·12·6

2.12.3 Other Qualifications

Validity date of all costs in this refinery study is fourth (4th) quarter of 1979. The accuracy of estimates of total capital investments is in the 'order of magnitude' range.

Inclusions in Estimates

- Permits, Authorizations, Royalties, etc.
- Taxes, Duty
- Spare Parts
- Catalysts
- On and Off Site Facilities
- Interest Charges
- Cost Incurred by Delays, Strikes, Premium Time, Forecasted Manpower Shortage
- Land Development
- Refinery Overhead Costs.

2.12.4 Capital Cost References

- UOP Process Division - Des Plaines, Illinois.
- Gulf Research and Development Company - Pittsburgh
- Hydrocarbon Research Inc. Research & Development Division - Lawrenceville, N.J.
- Exxon Research & Development - New Jersey
- Chevron Research - Calfornia
- Texaco Development Corporation - New York
- BP Trading Ltd. - England
- Humphrey and Glasgow - England

2.12.4 Capital Cost References (Cont'd)

- MHG International Ltd. - Calgary
- Shell Development Co. - Houston, Texas
- Bridge A.C., Gould G.D., Berkman J.F. "Residua Process Proven" Oil & Gas Journal, Jan. 19, 1981.
- Ondish G.F., Foyer J.A., McKinney J.D. "Save Crude: Feed Resid" Hydrocarbon Processing July 1976.
- National Petroleum Refiners Association "Combined Desulphurization and Catalytic Cracking for Crude Processing Flexibility" 1979 NPRA Annual Meeting.
- Guthrie M.G. "Process Plant Estimating Evaluation and Control". Craftsman Book Company of America.
- Kharbarda O.R. "Process Plant & Equipment Cost Estimation". Craftsman Book Company of America.
- Wood Gundy "Forecast" Canadian Economy.
- 1980 Canadian Process Plant Survey. Esso Resources Canada Ltd.
- Silver R. "Future looks Good for Saskatchewan". Oilweek, February 1981.
- "Canadian Refining Industry to Spend $1.5 Billion on Refineries", Oilweek, February 1981.
- "Gas Plants Investment Boosted 50%" - Oilweek, February 1981.
- "Big Inch Contractors", - Oilweek, February 1981.

2.13 OPERATING COSTS BASIS

The increased annual operating costs were calculated on the following basis, Table 2.13; and all costs involved are based on 1979 average.

TABLE 2.13

OPERATING COSTS BASIS

1. Annual Capital Charge: - 25% on Investment#

2. Fixed Operating Costs:

   . operating and supervisory personnel : - 24.864/yr/man**
   . maintenance - 3% of Capital Charge#
   . general, sales, administrative, taxes, insurance - 3.5% of Capital Charge#

3. Variable Operating Costs

		ATL.	QUE.	ONT.	WEST.
. Crude	$/Bbl	ø 23.18	ø 18.88	ø 14.73	ø 13.75
. Electrical Power,	¢/KWH	≠ 3.16	≠ 1.80	≠ 1.95	≠ 1.50
. Heavy Fuel Oil,	$/Bbl	x 17.35	x 18.83	x 19.83	x 18.04
. Fuel Gas,	$/1000 SCF	-	** 2.53	** 2.30	** 1.56
. Steam,	$/1000 lb	✱ 5.37	✱ 4.93	✱ 4.49	✱ 3.00
. Crude Oil Equivalent of Energy,	10^6 BTU/Bbl	5.82	5.78	5.66	5.67

. Cooling Water*** - 7.2 ¢/1000 USG

4. Catalyst and Chemicals

   . HDS Catalyst℗ - $4.7/lb
   . H_2 Plant Catalyst℗ - 0.165 ¢/lb of H_2
   . Amine℗ - $0.76/lb of amine

- as specified in RFP (37SS.KE 204-0-0516); ** - Statistics Canada
ø - EMR Canada; ≠ - Monenco Ltd.; x - Energy Analects;
✱ - Based on fuel cost equivalent of 1950 BTU/lb steam;
*** - Including capital charge
℗ - Engelhard Industries of Canada Ltd.

3. METHODOLOGY

3.1 ACTUAL AND SIMULATED SULFUR CONTENTS OF FUEL OILS (Tables 4.1.1, 4.2.1, 4.3.1, and 4.4.1)

3.1.1 Actual Case

The 1979 data from APCD Environment Canada (Reference 7) were used to calculate the actual sulfur content of HFO (#4,#5, and #6) including that of the refinery's own consumed HFO, LFO, Diesel Fuel and Stove Oil/Kerosene. Despite the fact that data are incomplete, (e.g. reports from some Quebec and Western refineries are missing; and there are some discrepancies, in Atlantic, Quebec and Ontario, regional sub-totals of sulfur reported in the summary sheets which do not agree with the summation of total sulfur reported by the individual refineries in that region) the sulfur content of fuel oils, except those of Western Region are generally acceptable for use in the study. In the case of Western Region, the sulfur content of fuel oils generated from simulated base case have been used as "1979 actual".

3.1.2 Simulated Base Case

A simulated Desulfurization Base Case for each region has been developed to reflect the 1979 refinery operations in terms of crude diet, product qualities, desulfurization operations, etc.. It was aimed to match the most possible operation a composite refinery would perform, in particular, the utilization of its installed desulfurization facilities, as mentioned in section 2.5, to achieve the product slate and sulfur and other specifications. An assumption that the existing Gas Oil HTU's could be used to process HCO has been made.

The hydrotreater utilization capacities were generated from the Desulfurization Base Case printouts; the % utilized were calculated

based on installed capacities.

Table 3.1.2 summarizes the most possible utilization of the existing hydrotreater capacity in four regions.

Table 3.1.2 UTILIZATION OF INSTALLED HYDROTREATER CAPACITY

Region	Kero BPCD	LGO BPCD	LCO BPCD	HCO BPCD	Total BPCD	% Utilized
Atlantic	45,800	16,300	24,400	6,100	92,600	90.1
Quebec	5,800	0	22,100	0	27,900	17.3
Ontario	0	0	0	0	0	0
Western	73,800	0	20,400	5,200	99,400	86.1

3.1.3 Case 1:

0.3 wt. % S max. in #2 Fuel Oil and Lighter

This simulation of this specification has been achieved in each region by utilizing the installed capacity of distillate and gas oil hydrotreaters. The desulfurization route selected to meet the new product sulfur specification is based on unit economy, i.e. capital and operating costs, sulfur conversion efficiency and capacity available. In this respect, the hydrotreaters were generally selected according to the following order:-

Kerosene HTU
Gas Oil HTU
Vac and/or atmospheric Resids HDS units

Using the similar data and calculation, Table 3.13 summarizes the most possible utilization of the existing hydrotreater capacity for Case 1, in four regions.

Table 3.13 UTILIZATION OF INSTALLED HYDROTREATER CAPACITY : Case 1

Region	Kero BPCD	LGO BPCD	LCO BPCD	HCO BPCD	Total BPCD	% Utilized
Atlantic	45,800	19,600	24,400	6,100	95,900	93.9
Quebec	22,100	23,900	23,500	10,000	79,500	49.3
Ontario	0	0	0	0	0	0
Western	73,900	12,300	18,900	5,200	110,300	95.5

3.1.4 Case 2 (i):

1.0 wt. % S max. in HFO

Following the same method mentioned in 3.1.3, and by maximizing the utilization of installed capacity of hydrotreaters before a new vacuum residue hydrodesulfurization unit would be added, Case 2(i) for Quebec, Ontario and Western were established. For Atlantic region, the composite refinery needs new atmospheric residuum desulfurization to achieve the product slate and new low sulfur fuel specification. It will be further discussed in 4.1.

The utilization of installed capacity of hydrotreaters in each region for Case 2(ii) is summarized in Table 3.1.4.

Table 3.14 UTILIZATION OF INSTALLED HYDROTREATER CAPACITY: CASE 2 (i)

Region	Kero BPCD	LGO BPCD	LCO BPCD	HCO BPCD	Total BPCD	% Utilized
Atlantic	45,800	25,700	24,400	6,100	102,000	100
Quebec	22,100	47,700	47,000	10,000	126,800	78.7
Ontario	0	0	0	4,800	4,800	5.9
Western	73,900	4,900	31,400	5,200	115,400	100

3.1.5 Case 2(ii):

0.5 wt. % S max. in HFO

Similar to Case 2 (i), Case 2 (ii) were simulated for four regions. For Atlantic region, again, additional atmospheric resid HDS units would be required to achieve the low sulfur fuel specification. It will be further discussed in 4.1.3.

The utilization of installed capacity of hydrotreaters for Case 2 (ii) in each region, is shown in Table 3.15.

Table 3.15 UTILIZATION OF INSTALLED HYDROTREATER CAPACITY: CASE 2 (ii)

Region	Kero BPCD	LGO BPCD	LCO BPCD	HCO BPCD	Total BPCD	% Utilized
Atlantic	45,800	25,700	24,400	6,100	102,000	100
Quebec	22,100	47,700	47,000	10,000	126,800	78.7
Ontario	0	0	0	9,700	9,700	12.0
Western	73,900	4,900	31,400	5200	115,400	100

3.2 CALCULATION OF SULFUR REDUCTION IN FUELS

Having known the sulfur content of fuel oils for the 1979 actual case and the new specifications from 3.1, the annual (325 days as defined in the RFP 37SS.KE204-0-0516) sulfur reduction or increase (as denoted by "-" in Tables 4.1.2, 4.2.2. and 4.4.2) in refinery own HFO and Light Fuel Oils consumption, saleable HFO and light fuel oils products (excluding own consumption) can be calculated.

In the calculation, the data used for own consumption, saleable HFO and Light Fuel Oil products are detailed in 2.11.1, 2.11.2 and 2.11.3 respectively. The densities used for HFO, LFO, Diesel Fuel and Stove Oil/Kerosene are those predicted from the simulation and can be found in the printouts.

3.3 ADDITIONAL HYDRODESULFURIZATION AND SUPPORTING UNITS REQUIRED

Following the principle that the utilization of installed capacity of hydrotreater should be maximized before any additional hydrodesulfurizer would be added to achieve a low sulfur fuel oil specification, the new HDS units required for each new specification can be determined by using the results of case simulation. In the case simulation of Atlantic region, some hand calculations were required due to the limitation of the model which did not include the atmospheric residue desulfurization process.

The additional H_2 plants required were sized according to the following formula:

> Additional H_2 from new plants + H_2 available from existing reformer = H_2 consumption of all other existing hydrotreaters + 120% H_2 consumption of new vacuum and/or atmospheric resids HDS units.

If H_2 available is more than total H_2 consumed, no additional H_2 plant would be required. The H_2 consumption data from 2.10 and reformer's H_2 data predicted by computer simulation for each region were used for the calculation.

The feedstock to new H_2 plant was initially assumed to be naphtha. If naphtha available was insufficient, it would then be supplemented by refinery fuel gas. The additional amine plants required for treating sour fuel gas generated form new vacuum and/or atmospheric resids HDS units were estimated by using the yield data of Tables 2.9.1, 2.9.2 and 2.9.3.

Furthermore, it was assumed that sour fuel gas produced from the existing hydrotreaters, as a result of the maximum utilization of installed capacity, would be processed by the existing facilities.

The additional sulfur recovery plants required were sized according to the total sulfur converted from the new vacuum and/or atmospheric resids HDS units, i.e., 85% of total sulfur in feed to this units. The recovery efficiencies, 99% and 97.5% for sulfur plants larger and smaller than 100 STPD respectively, were also considered in sizing new sulfur plants.

Sour Water Strippers are not included in the capital and operating costs estimate. Some early calculations indicated that relatively little additional sour water produced by new HDS units, e.g. in 1.0 wt. % S in HFO case, 17-28 USGPM and in 0.5 wt. % S in HFO case, 30-48 USGPM, for a refinery in Quebec, could be assumed to be processed by the existing S.W.S. facilities. S.W.S. are normally designed to and capable of handling additional loads.

In each region, the desulphurization and supporting units (H_2, amine and sulfur plants) required by a composite refinery were arbitrarily broken down into smaller units, the capacity of each of them was in accordance with the crude processing capability of each refinery, i.e. refinery with higher crude capacity would have larger HDS and supporting units, as shown in Tables 4.1.3, 4.2.3, 4.3.3, and 4.4.3.

The regional vacuum and/or atmospheric HDS capacities, shown for 2 levels of desulfurization, i.e. 0.5 and 1.0 wt. % S in HFO, are generated from the results of case simulation based on 85% S conversion of the unit as mentioned in 2.6; and they are the design capacities used for capital investment estimation.

3.4 CALCULATION OF INCREASED CRUDE OIL REQUIREMENTS

The increased crude oil requirements include feed, 3.4.1, plus that equivalent to energy requirements, 3.4.2.

3.4.1 Increased Crude Feed Requirements

Due to the desulfurization loss and product yields, desulfurized fuel oils produced by the hydrotreaters would generally be less than the feed, e.g. desulfurized LCO is 98.6 LV% of LCO feed, Table 2.9.1. Additional crude oil would be required to compensate the reduction should the product slate and specification be maintained.

By applying the hydrotreater yield data, Tables 2.9.1, 2.9.2 and 2.9.3, increased crude oil required to meet the production, in particular, HFO (stream ⟨47⟩ in the printouts), Diesel Fuel ⟨46⟩, LFO ⟨54⟩ and Stove Oil ⟨44⟩ can be calculated for each case by material balance.

The crude oil consumption used in each base case, for each region were from Tables 2.3.1, 2.3.2, 2.3.3 and 2.3.4. New crude feed requirement for each case in each region are shown in the "New Crude Case" printout, stream ⟨0⟩. The crude feed data (base case and new requirements) are tabulated as follows:

Table 3.4.1 NEW CRUDE FEED REQUIRED DUE TO DESULFURIZATION

Region	NEW CRUDE FEED REQUIRED BPCD			CRUDE OIL BASE CASE BPCD
	0.3 wt.% S LFO	1.0 wt.% S HFO	0.5 wt.% S HFO	
Atlantic	314,278	314,716	317,312	313,229
Quebec	511,185	512,705	514,303	510,472
Ontario	605,223	605,223	608,570	605,147
Western	525,642	526,570	527,506	525,420
CANADA	1,956,328	1,959,214	1,967,731	1,954,268

The annual incremental crude oil requirements for each new fuel oil specification will then be calculated accordingly.

3.4.2 Increased Crude Oil Equivalent of Energy

The incremental energy requirements for each new low S fuel spec., Tables 4.1.6, 4.2.6, 4.3.6 and 4.4.6, were calculated in terms of crude oil equivalent barrels for the convenient of auditing, Tables 4.1.7, 4.2.7, 4.3.7 and 4.4.7. The data used for the conversion are 5.82×10^6 BTU/Bbl, 5.78×10^6 BTU/Bbl, 5.66×10^6 BTU/Bbl and 5.67×10^6 BTU/Bbl for Atlantic, Quebec, Ontario and Western, respectively, Table 2.13.

3.5 PREDICTION OF PRODUCTION CHANGE OF SOME REFINERY PRODUCTS DUE TO DESULFURIZATION

Having optimized the hydrotreated processing scheme, the production changes of heavy fuel oil and light fuel oils (including #2, Fuel Oil Diesel Fuel and Stove Oil/Kerosene) due to desulfurization could be predicted.

The annual increase and decrease, as denotes by "+" and "-" respectively in Tables 4.1.5. (a), 4.2.5. (a), 4.3.5. (a) and 4.4.5. (a) of HFO and LFO were estimated by comparing the manually calculated new product yields with the product slate for 1979, Tables 2.4.1.1 to 2.4.1.4 inclusive.

Furthermore, the annual production of fuel gas (gross), naphtha (gross) and sulfur due to vacuum and/or atmospheric resids desulfurization were also manually calculated, based on product yields data of Tables 2.9.1 - 2.9.3, as shown in Tables 4.1.5 (b), 4.2.5 (b), 4.3.5 (b) and 4.4.5 (b).

The fuel gas was assumed to have a heating value of 600 BTU/SCF and the production includes fuel gas consumption of HDS. The treated naphtha production was assumed to be used as feedstock to new H_2 plants. Further discussion will be followed in Section 4.

3.6 CALCULATION OF INCREASED ENERGY REQUIREMENTS

The energy requirement for desulfurization in order to achieve the new S specifications was broken down into the following categories:

(i) Fuel
(ii) Electricity
(iii) Steam
(iv) Cooling Water

The requirement for each category in each region for each specification was calculated as the sum of requirements for all processing units involved , i.e., hydrotreating, H_2 plant, amine and sulfur plants, in the desulfurization.

The energy requirements data used for distillate and gas oil hydrotreaters were originated from Nelson's "Refinery Operating Costs" (Reference 8), Gulf's "Hydrocarbon Processes" (Reference 9), Reference 2 and in-house information. The data from Reference 6 were extensively used for resids HDS. As for supporting units, information from Reference 8 and in-house data were used.

Increased annual energy requirements for fuel, electricity and steam were expressed in terms of 10^6 BTU so that total energy can be summarized as shown in Table 4.1.6, 4.2.6, 4.3.6 and 4.4.6.

Furthermore, increased annual energy requirements for fuel, electricity and steam were also expressed in terms of crude oil equivalent barrels, Tables 4.1.7, 4.2.7, 4.3.7 and 4.4.7, using Table 2.13 data.

3.7 CALCULATION OF INCREASED COST OF OPERATING MATERIALS

The cost of operating materials was broken into:-

(i) energy
(ii) cooling water
(iii) catalysts
(iv) chemicals

(i) Increased Cost of Energy

This increased annual cost of energy for each specification in each region was claculated from total energy requirements (except cooling water), Tables 4.1.6, 4.2.6, 4.3.6 and 4.4.6, and unit cost data, Table 2.13. Natural gas and/or fuel gas was assumed to be the fuel for all regions except Atlantic. In Atlantic region, the type of fuel was assumed to be heavy fuel oil.

Furthermore, the increased annual cost of energy for each specification and in each region was calculated, Tables 5.2.1 (a), 5.2.2 (a), 5.2.3 (a) and 5.2.4 (a), by using crude oil equivalent data from Tables 4.1.7, 4.2.7, 4.3.7 and 4.4.7, and crude oil prices from Table 2.13 and those specified in "RFP".

(ii) Increased cost of Cooling Water

The increased annual cost of cooling water for each new S specification in each region was calculated accordingly to the cooling water requirement data, Tables 4.1.6, 4.2.6, 4.3.6 and 4.4.6 and the adjusted unit cost of mid-1979 (Reference 6), using Nelson cost indexes. The unit cost of cooling water specified in Table 2.13 includes the capital charges.

(iii) Increased cost of Catalysts

The catalyst costs include those for the make-up requirements of distillate and gas oil hydrotreaters, vacuum and/or atmospheric resids HDS and hydrogen plants (if required). The requirements data were originated from Reference 6 and Reference 9. The 1979 unit costs for catalysts used were obtained from Engelhard Industries of Canada Ltd.

(iv) Increased cost of Chemicals

The chemicals involved was assumed to be the amines which would be used for treating sour fuel gas. The consumption of amine was estimated to be 3 lbs/MMSCF (Reference 8) and the unit cost for amine, Table 2.13, was adjusted to mid-1979 using Nelson cost indexes.

3.8 ESTIMATION OF CAPITAL INVESTMENT COSTS

The total capital investment cost is given per refinery location. The estimate structure of each refinery comprises of:

Unit #1

1. New Equipment _____
2. Labor and Material _____
3. Offsites, etc. _____

Direct Costs _____

Unit #2

1. New Equipment _____
2. Labor and Material _____
3. Offsites, etc. _____

Direct Costs _____

Unit #3

1. New Equipment _____
2. Labor and Material _____
3. Offsites, etc. _____

Direct Costs _____

Unit #4

1. New Equipment _____
2. Labor and Material _____
3. Offsites, etc. _____

Direct Costs _____

Unit #5

1. New Equipment _____
2. Labor and Material _____
3. Offsites, etc. _____

Direct Costs _____

TOTAL DIRECT COSTS _____

H.O. ENGINEERING COST _____

CATALYST COST _____

TOTAL CAPITAL INVESTMENT _____

The TOTAL DIRECT COSTS are the summation of the Direct Costs of each process unit. The H.O. ENGINEERING COST and CATALYST COST are per refinery basis, respectively. Therefore, the TOTAL CAPITAL INVESTMENT of a refinery consists of TOTAL DIRECT COSTS, H.O. ENGINEERING COST and CATALYST COST.

3.9 CALCULATION OF INCREASED OPERATING COSTS

1. Annual Capital Charges:

As specified in "RFP", capital charges per year, which may include depreciation, interest, etc., was estimated at 25% of the capital investment cost.

2. Fixed Operating Costs

a. Operating and Supervisory Personnel:

The distribution of additional manpower per plant to cover 24 hours was assumed to be as follows:-

Hydrodesulfurization Unit	8 Men
Hydrogen Plant	8 Men
Amine Plant	4 Men
Sulfur Recovery Plant	8 Men
Supervisory	4 Men
TOTAL	32 Men

Because of additional atmospheric resid HDS assigned for Atlantic and no requirement for H_2 plant in Ontario and Western, additional personnel per refinery would be needed by region:

Atlantic	40 Men/refinery
Quebec	32 Men/refinery
Ontario	24 Men/refinery
Western	24 Men/refinery

Assuming manpower requirements are equal regardless of unit/plant size.

The annual cost of operating and supervisory personnel, for a region, in $/year, C, was calculated as:-

$$C = n \times P \times S$$

where n: number of refineries in a region
P: number of additional personnel required
S: average annual salary for operating and supervisory personnel, $/man/year.

b. Maintenance

The cost was calculated as 3% of the annual capital charges, as specified by "RFP".

c. General, Sales, Administrative, Taxes, Insurance

These costs were estimated to be 3.5% of the annual capital charge, as specified by "RFP".

3. Variable Costs

a. Cost of Increased Crude

The cost of additional crude feed, Table 5.3.1 to 5.3.4 inclusive, was calculated for several cases ranging from mid-1979 price to $35/Bbl as required by "RFP".

Further, the cost of total increased crude oil requirements (feed + equivalent to energy requirements), Tables 5.4.1 to 5.4.4 inclusive, were similarly calculated for several cases ranging from mid-1979 price to $35/Bbl.

b. Cost of Additional Energy Requirements

Refer to 3.7 for method of calculation.

4. Cost of Catalysts and Chemicals

Refer to 3.7 for method of calculation.

5. Credit for Sulfur

An assumption was made that all sulfur recovered was creditable at a 1979 price of $31 per long ton.

The increased annual operating costs were calculated by summation of the annual capital charge, the fixed operating costs, the variable costs for each crude price and the cost of catalyst , chemicals, and minus the credit for sulfur.

The increased annual operating costs were also presented on the basis of per barrel crude processed, e.g., Tables 5.3.1 - 5.3.4, Part IV.

4. RESULTS AND DISCUSSIONS

4.1 ATLANTIC REGION

4.1.1 Actual and Simulated Sulfur Contents of Fuel Oils, Table 4.1.1

The results of LFO and Stove Oil/Kerosene from the simulated base case printouts A-S-B matched well with that of 1979 Actual. There was a fairly large difference of the S content of Own HFO, 3.157 wt. %, and Saleable HFO, 2.664 wt. %, reported in the 1979 Actual case. A simulated S content of 2.852 wt. % was thought to be acceptable since only one value was assigned for both HFO's. The closest value of S of Diesel Fuel in the simulated base case was 0.192 wt. %. The discrepancy may be due to the deviation in hydrotreater utilization assumption. No attempts were made to optimize the case due to limitation of non-LP program. The % utilization of installed hydrotreaters was predicted at 90.7 %, Table 3.1.2.

In the 0.3 wt. % S in LFO case, Case (i), printouts A-1, the S content of LFO was successfully reduced to 0.298 wt. % without additional distillate or gas oil hydrotreater capacity. The % utilization of the installed hydrotreaters was 93.9%, Table 3.1.2.

In the 1.0 wt. % S in HFO case, Case 2 (i), printouts A-2, the S content of HFO could only be reduced to 1.42 wt. % by 100% utilization of the existing hydrotreater capacity, Table 3.1.3. However, further manual calculation resulted that the S content of HFO was successfully reduced to 1.0 wt % by the installation of vacuum and atmospheric resids HDS units of 30,900 BPSD and 45,400 BPSD respectively, Table 4.1.3, in addition to 100% utilization of the existing hydrotreater capacity, Table 3.1.4.

In the 0.5 wt. % S in HFO case, Case 2 (ii), similar to case 2 (i) discussed in the preceding paragraph, vacuum and atmospheric HDS units of 47,400 BPSD and 45,400 BPSD respectively were required in addition to 100% utilization of the existing hydrotreater capacity, Table 3.1.5, in order to meet the new low S level in HFO.

In both 2 (i) and 2 (ii) cases, as a result of S reduction of HFO, the S content of LFO and Diesel Fuel were accordingly reduced to 0.211 wt. % and 0.139 wt. % respectively.

TABLE 4.1.1

ACTUAL & SIMULATED SULFUR CONTENTS OF FUEL OILS ATLANTIC REGION

Item	Case \ Sulfur wt.%	Refinery Own Consumption				Saleable	Light Fuel Oils		
		HFO	LFO	Diesel Fuel	Stove Oil/ Kerosene	HFO (#4,#5,#6)	LFO #2	Diesel Fuel	Stove Oil/ Kerosene
A	'79 Actual*	3.157	0.343	0.346	0.088	2.664	0.343	0.346	0.088
S-B	Simulation Base Case	2.852	0.344	0.192	0.088	2.852	0.344	0.192	0.088
1	Simulation #2 Fuel Oil & Lighter 0.3 wt.% S, max.	2.851	0.298	0.174	0.088	2.851	0.298	0.174	0.088
2 (i)	Simulation Heavy Fuel Oil 1.0 wt.% S, max.	0.994	0.211	0.139	0.088	0.994	0.211	0.139	0.088
2(ii)	Simulation Heavy Fuel Oil 0.5 wt.% S, max.	0.494	0.211	0.139	0.088	0.494	0.211	0.139	0.088

* APCD, Environment Canada, Dec. '79 Data

4.1.2 Prediction of Annual Sulfur Reduction in Fuels, Table 4.1.2

In Case 1, the S in Saleable HFO shows an annual increase of 10.032 tonnes as a result of the increase of S wt. % from 2.664 wt. % , in Case A, to 2.851 wt. % in this case.

This may be due to the fact that one value for S of HFO having been assigned, a compromise of different S values for Refining Own HFO and Saleable HFO as discussed in 4.11, and the possible discrepancies of actual S data.

Further, the reduction of S in LFO to 0.3 wt. % max. would not necessarily reduce the S of HFO simultaneously if the HFO had already met the 1979 S specification, i.e. 3.5 wt. % max. It is possible, as indicated by this case, that the S content of HFO would vary little or even increase from 1979 Actual data.

In Case 2 (i) and (ii), the annual S reduction was substantial. The impact of Case(2) on sulfur reduction of Light fuel oils of own consumption is much less than that of light fuel oil products simply because of very small amount of light fuel oils being consumed.

The combination of Case (i) and Case (2) is the same as Case (2).

TABLE 4.1.2

PREDICTION OF ANNUAL SULFUR REDUCTION IN FUELS ATLANTIC REGION

			(A)				(B)	(C)			(A)+(B)+(C)
Item	Specification / ** Annual S Reduction		P Refinery Own Fuel Consumption				P * Saleable HFO (#4, #5, #6) t	P @ Light Fuel Oil Products			TOTAL metric tonne t
			HFO t	Light Fuel Oils				LFO t	Diesel t	Stove Oil t	
				LFO t	Diesel t	Stove Oil t					
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		566	2	19	-	-10,032	1,576	2,372	-	-5,497
			Sub-Total = 587					Sub-Total = 3,948			
2	HFO (#4, #5, #6)	(i) 1.0 wt.% S, max.	4,002	5	22	-	89,587	4,622	2,854	-	101,092
			Sub-Total = 4,029					Sub-Total = 7,476			
		(ii) 0.5 wt.% S, max.	4,927	5	22	-	116,410	4,622	2,854	-	128,840
			Sub-Total = 4,954					Sub-Total = 7,476			
3	Impact of item 2 on sulfur of		-	5	22	-		4,622	2,854	-	7,503
				Sub-Total = 27				Sub-Total = 7,476			
@4	Combination of 1 and	2 (i)	4,002	5	22	-	89,587	4,622	2,854	-	101,092
			Sub-Total = 4,029					Sub-Total = 7,476			
		2 (ii)	4,927	5	22	-	116,410	4,622	2,854	-	128,840
			Sub-Total = 4,954					Sub-Total = 7,476			

P Based on Statistics Canada - Refined Petroleum Products '79

@ Same as Item 2

* Incl. interprovincial, export/import, domestic sales and corrections for inventory changes and losses

@ Excl. own consumption but including corrections for inventory changes and losses

** Annual = 325 days per year

4.1.3 Design Capacity for Additional Plants Required, Table 4.1.3

No additional capacity of hydrotreater would be required for desulfurization to achieve 0.3 wt. % S max. in LFO.

For 1.0 wt. % S max. in HFO and 0.5 wt. % S max. in HFO cases, the requirements of additional vacuum and atmospheric resids HDS units and their supporting plants, i.e. H_2, Amine and Sulfur Plants are shown. The on-stream factor was assumed to be 0.89.

The desulfurization of atmospheric resid would be required in addition to that of vacuum resid because insufficient desulfurized vacuum resid is being produced and charged to the HFO blending pool. More desulfurized fuel oil would be needed and the optimized choice is that from atmospheric resid. The alternative route would be to enlarge vacuum unit so that more residue would be made available for desulfurization. In this case larger vacuum resid HDS unit would be required. The other alternative would be to desulfurize enough quantity of HVGO, if available. Both alternatives have been proved to be impractical because the availability of HVGO and vacuum resid, that would have been produced, is limited by the reduced crude feedstock to vacuum unit. To increase the reduced crude production would defeat the optimization purpose of crude oil savings.

TABLE 4.1.3

DESIGN CAPACITY FOR ADDITIONAL PLANTS ATLANTIC REGION

Refinery	Crude Capacity BPCD	%	0.5 % Sulfur in HFO					1.0 % Sulfur in HFO					CODE
			* Vacuum Residue HDS (BPSD)	** Atmospheric Residue HDS (BPSD)	@ H_2 Plant 97% (10^6 SCFD)	Amine (10^6 SCFD)	Sulfur (STPD)	* Vacuum Residue HDS (BPSD)	* Atmospheric Residue HDS (BPSD)	@ H_2 Plant 97% (10^6 SCFD)	Amine (10^6 SCFD)	Sulfur (STPD)	
Ultramar	14,000	3.1	1,500	1,400	4.2	2.4	P 19	1,000	1,400	3.2	2.0	P 16	A-1
Gulf	81,000	18.0	8,500	8,200	24.3	13.9	P 109	5,600	8,200	18.7	11.9	P 90	A-2
Imperial	86,900	18.7	8,900	8,500	25.2	14.4	P 113	5,800	8,500	19.5	12.3	P 94	A-3
Texaco	20,000	4.5	2,200	2,100	6.1	3.4	P 27	1,400	2,100	4.7	3.0	P 23	A-4
Irving	250,000	55.7	26,300	25,200	75.2	42.9	P 338	17,100	25,200	57.9	37.8	P 283	A-5
TOTAL	448,900	100.0	47,400	45,400	135.0	77.0	606	30,900	45,400	104.0	67.0	506	

On Stream Factor 0.89

* Vacuum Residue HDS: HRI H-Oil Process

** Atmospheric Residue HDS: HRI H-Oil Process

@ H_2 Plant Feedstock = Naphtha

P Sulfur Recovery 97.5%

P Sulfur Recovery 99.0%

4.1.4 Increased Annual Crude Feed Requirements, Table 4.1.4

The resort of additional crude annually required to compensate the desulfurization losses are presented. The product slates would be maintained for each new S fuel specifications if the additional crude are processed.

TABLE 4.1.4

INCREASED ANNUAL CRUDE FEED REQUIREMENTS ATLANTIC REGION

Simulated Base Case: 1979 Total Crude Oil Requirement
= 18,177,000 M^3 or 114,329,000 Bbl. (or 313,229 BPCD■)

Case	Increased Crude Feed Specifications	* Annual Requirements		Daily Requirements BPCD
		M^3	Bbl.	
1	#2 Fuel Oil and Lighter, 0.3 wt.% S, max.	54,203	340,925	1,049
2 (i)	HFO (#4,#5,#6) 1.0 wt.% S, max.	76,835	483,275	1,487
2 (ii)	HFO (#4,#5,#6) 0.5 wt.% S, max.	213,039	1,339,975	4,123
1 + 2 (i)	Combination of case 1 and case 2 (i)	76,835	483,275	1,487
1 + 2 (ii)	Combination of case 1 and case 2 (ii)	213,039	1,339,975	4,123

* Annual = 325 Days Per Year

■ See Simulated Base Case Printout

4.1.5 ANNUAL CHANGE OF REFINERY PRODUCTION DUE TO DESULFURIZATION

4.1.5.1 Prediction of Annual Change of Heavy & Light Fuel Oils Production, Table 4.1.5 (a)

The losses of HFO and LFO's (#2 FO, Diesel Fuel & Stove) production in terms of barrels due to desulfurization, for each new S fuel specification, are presented. In this respect, no additional crude oil is required.

4.1.5.2 Prediction of Annual Increase of Fuel Gas, Naphtha and Sulfur Production Due to Residue Desulfurization, Table 4.1.5 (b)

The products of vacuum and atmospheric resids HDS namely, fuel gas, naphtha (C_5 -375^{o}F) and sulfur, are estimated.

Both fuel gas and naphtha could be used to produce H_2 which are required for hydrodesulfurization. In Atlantic region, for Case 2(i), all treated naphtha produced from vacuum and atmospheric resid HDS would be used up. In addition fuel gas estimated at 7716 x 10^6 SCF/annum, equivalent to 735 FOEB (assume fuel gas LHV = 600 BTU/SCF), would be required to supplement naphtha.

TABLE 4.1.5 (a)

PREDICTION OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OILS
PRODUCTION DUE TO DESULFURIZATION ATLANTIC REGION

Design Basis: Crude Feed = 313,229 BPCD

Item	* Annual Change / Specification		ᵽ Existing Refinery Output	
			Heavy Fuel Oil M Bbl.	Light Fuel Oils (LFO, Diesel Fuel & Stove Oil) M Bbl.
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		- 75	- 38
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S. max.	- 394	- 38
		(ii) 0.5 wt.% S. max.	- 1,153	- 38
4	Combination of 1 and	2 (i)	- 394	- 38
		2 (ii)	- 1,153	- 38

* Annual = 325 Days Per Year

ᵽ Including Own Consumption

"+" and "-" denotes increased and decreased production respectively

TABLE 4.1.5 (b)

PREDICTION OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA AND SULFUR PRODUCTION DUE TO RESIDUE DESULFURIZATION ATLANTIC REGION

Design Basis: Crude Feed = 313,229 BPCD

Item	* Annual Production Change / Specification		Atmospheric and Vacuum Residue HDS		
			Fuel Gas (Gross) M FOEB **	Naphtha (Gross) M Bbl.	Sulfur 97.5% Recovered metric tonne, t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		-	-	-
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S, max.	1,337	686	98,459
		(ii) 0.5 wt.% S, max.	1,640	2,020	117,946
4	Combination of 1 and	2 (i)	1,337	686	93,459
		2 (ii)	1,640	2020	117,946

* Annual = 325 Days Per Year

** FOEB = 6.3×10^6 BTU (Fuel Gas LHV = 600 BTU/SCF)

4.1.6 Increased Annual Energy Requirements, Table 4.1.6

The summary of energy requirements broken down for Fuel, Electricity, Steam and Cooling Water is presented.

Further, Tables 4.1.6 (a), (b), and (c) show respectively the additional requirement of individual processing unit, for each new S fuel specification. S Recovery plants, if required, would generate export steam which are credited to the total energy in term of BTU's. The energy consumed in Hydrogen plants includes fuels for vapourizer, reformer and boiler.

4.1.7 Crude Oil Equivalent of Increased Annual Energy Requirements, Table 4.1.7

The results of converting increased annual energy requirements, i.e. Table 4.16. excluding cooling water, to crude oil equivalent barrels are shown in Table 4.1.7. They are also expressed in terms of % of new crude feed which is 100%.

TABLE 4.1.6

INCREASED ANNUAL ENERGY REQUIREMENTS ATLANTIC REGION

Case	Increased Energy / Specification	Increased Annual* Energy Requirements				
		Fuel FOEB (10^6 BTU)	Electricity 10^3 kW-h (10^6 BTU)	Steam 10^3 lb. (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	41,094 (258,890)	5,469 (54,686)	27,872 (27,872)	266	(341,448)
2 (i)	HFO (#4, #5, #6) 1.0 wt.% S, max.	1,633,840 (10,293,193)	232,894 (2,328,935)	10,709,695 (10,709,695)	19,357	(23,331,823)
2 (ii)	HFO (#4, #5, #6) 0.5 wt.% S, max.	2,182,232 (13,748,060)	343,608 (3,436,075)	13,956,955 (13,956,955)	24,460	(31,140,090)
1 + 2 (i)	Combination of case 1 and case 2 (i)	1,633,840 (10,293,193)	232,894 (2,328,935)	10,709,695 (10,709,695)	19,357	(23,331,823)
1 + 2 (ii)	Combination of case 1 and case 2 (ii)	2,182,232 (13,748,060)	343,608 (3,436,075)	13,956,955 (13,956,955)	24,460	(31,140,090)

* Annual = 325 Days Per Year

** Fuel, 1 FOEB = 6.3×10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

o Same as case 2 (i)

• Same as case 2 (ii)

TABLE 4.1.6 (a)

INCREASED ANNUAL ENERGY REQUIREMENTS ATLANTIC REGION

Case: 0.3%S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	41,094 (258,890)	5,469 (54,686)	27,872 (27,872)	266	(341,448)
Vacuum Residue and Atmospheric Residue HDS	-	-	-	-	-
Hydrogen	-	-	-	-	-
Amine	-	-	-	-	-
Sulfur	-	-	-	-	-
TOTAL	41,094 (258,890)	5,469 (54,686)	27,872 (27,872)	266	(341,448)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

TABLE 4.1.6 (b)

INCREASED ANNUAL ENERGY REQUIREMENTS ATLANTIC REGION

Case: 1% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	60,947 (383,969)	8,596 (85,955)	50,207 (50,207)	473	(520,131)
Vacuum Residue and Atmospheric Residue HDS	151,147 (952,224)	196,870 (1,968,700)	211,453 (211,453)	636	(3,132,377)
Hydrogen	1,421,746 (8,957,000)	23,660 (236,600)	11,323,000 (11,323,000)	17,387	(20,516,600)
Amine	- P	479 (4,790) P	13,065 (13,065)	39	(17,855)
Sulfur	-	3,289 (32,890)	-888,030 (-888,030) e	822	(-855,140)
TOTAL	1,633,840 (10,293,193)	232,894 (2,328,935)	10,709,695 (10,709,695)	19,357	(23,331,823)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

e Credit for steam

P All pumps are motor driven

p Reboiler heated by steam

TABLE 4.1.6 (c)

INCREASED ANNUAL ENERGY REQUIREMENTS ATLANTIC REGION

Case: 0.5% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	60,947 (383,969)	8,596 (85,955)	50,207 (50,207)	473	(520,131)
Vacuum Residue and Atmospheric Residue HDS	275,749 (1,737,216)	299,810 (2,998,100)	257,108 (257,108)	1,021	(4,992,424)
Hydrogen	1,845,536 (11,626,875)	30,712 (307,125)	14,698,125 (14,698,125)	21,937	(26,632,125)
Amine	- P	551 (5,505)	15,015 (15,015)	45	(20,520)
Sulfur	-	3,939 (39,390)	-1,063,500 (-1,063,500)	985	(-1,024,110)
TOTAL	2,182,232 (13,748,060)	343,608 (3,436,075)	13,956,955 (13,956,955)	24,460	(31,140,090)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

● Credit for steam

P All pumps are motor driven

p Reboiler heated by steam

TABLE 4.1.7

CRUDE OIL EQUIVALENT OF INCREASED ANNUAL ENERGY REQUIREMENTS ATLANTIC REGION

Case	Increased Annual * / Specification	Energy Requirement 10^6 BTU	Crude Oil Equivalent Bbl	% Energy
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	341,448	58,680	0.06 #
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	23,331,823	4,009,770	3.92 ##
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	31,140,090	5,351,680	5.19 ###
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	23,331,823	4,009,770	3.92 ##
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	31,140,090	5,351,680	5.19 ###

Heating Value of Crude = 5,818,750 BTU/Bbl

* Annual = 325 days per year;

\# New Crude Feed, 314,278 BPCD = 100%;

\#\# New Crude Feed, 314,716 BPCD = 100%;

\#\#\# New Crude Feed 317,352 BPCD = 100%

4.2 QUEBEC REGION

4.2.1 Actual & Simulated Sulfur Contents of Fuel Oils, Table 4.2.1

Due to incomplete sulfur content data of HFO and LFO's, 1979 actual case should be treated with some reservation, e.g. S content of Refinery Own HFO. Nevertheless, the results of simulated base case, printouts Q-S-B, were reasonably close to reflect the actual refinery desulfurization operations. The % utilization of installed hydrotreater capacity was estimated at 17.3% in 1979, Table 3.1.2.

In Case 1, printouts Q-1, the S content of LFO was successfully decreased to 0.301 wt. % from the actual 0.367 wt. %, by merely utilizing 49.3 % installed hydrotreater capacity, Table 3.1.3. At the same time, the HFO sulfur was also reduced to 2.050 wt. %. The advantage of achieving sulfur reduction in fuel oils by this specification is evident.

In Case 2 (i), printouts A-2(i), the S of HFO was exactly reduced to spec. i.e. 1.0 wt. %, using 78.7% of installed hydrotreater capacity, Table 3.1.4 plus an additional vacuum resid HDS unit of 43,000 BPSD, Table 4.2.3. These would have some reserved capacity of distillate hydrotreater in 1979, in Quebec, particularly Kerosene HTU if Case 2 (i) were to be performed.

In Case 2 (ii), printouts A-2(ii), similar to Case 2(i), by utilizing 78.7% of installed hydrotreater capacity, Table 3.1.5 plus an additional vacuum resid HDS unit of 65,300 BPSD, Table 4.2.3, the low S fuel spec. of 0.5 wt. % HFO, was achieved. The reserved capacity for kerosene HTU was the same as that of Case 2 (i).

This indicates that S content in Stove Oil could be further reduced to less than 0.114 wt. %, if required.

In both 2 (i) and 2 (ii) Cases, the S level of LFO and Diesel Fuel were lowered to 0.095 wt. % and 0.099 wt. % as a result of sulfur reduction in HFO.

TABLE 4.2.1

ACTUAL & SIMULATED SULFUR CONTENT OF FUEL OILS QUEBEC REGION

Item	Case \ Sulfur wt.%	Refinery Own Consumption				Saleable	Light Fuel Oils		
		HFO	LFO	Diesel Fuel	Stove Oil/ Kerosene	HFO (#4,#5,#6)	LFO #2	Diesel Fuel	Stove Oil/ Kerosene
A	'79 Actual*	1.936	0.367	0.381	0.138	2.393	0.367	0.381	0.138
S-B	Simulation Base Case	2.218	0.368	0.307	0.137	2.218	0.368	0.307	0.137
1	Simulation #2 Fuel Oil & Lighter 0.3 wt.% S, max.	2.050	0.301	0.225	0.114	2.050	0.301	0.225	0.114
2 (i)	Simulation Heavy Fuel Oil 1.0 wt.% S, max.	1.000	0.095	0.099	0.114	1.000	0.095	0.099	0.114
2(ii)	Simulation Heavy Fuel Oil 0.5 wt.% S, max.	0.495	0.095	0.099	0.114	0.495	0.095	0.099	0.114

* APCD, Environment Canada, Dec. '79 (Data on sulfur content of refinery products and own consumption are not complete for Quebec Region)

4.2.2. Prediction of Annual Sulfur Reduction in Fuels, Table 4.2.2

In Case 1, the lowering of S level in HFO was strongly reflected in the reduction of S in Saleable HFO, 18,378 t annually, in addition to the required lower S in LFO's which decreased an amount of 6818 t sulfur.

In Case 2 (i) and 2 (ii) substantial amounts of S were accordingly reduced as shown.

The influence of implying spec. 2 (i) or 2 (ii) would accompany a reduction of 19.475 t sulfur from LFO's (excluding refinery own case) annually.

TABLE 4.2.2

PREDICTION OF ANNUAL SULFUR REDUCTION IN FUELS QUEBEC REGION

Item	Specification / ** Annual S Reduction		(A) P Refinery Own Fuel Consumption HFO t	(A) Light Fuel Oils LFO t	(A) Diesel t	(A) Stove Oil t	(B) P * Saleable HFO (#4, #5, #6) t	(C) P ● Light Fuel Oil Products LFO t	(C) Diesel t	(C) Stove Oil t	(A)+(B)+(C) TOTAL metric tonne t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		-739	4	41	-	18,378	3,082	3,650	86	24,502
			Sub-Total = -694					Sub-Total = 6,818			
2	HFO (#4, #5, #6)	(i) 1.0 wt.% S, max.	6,289	18	74	-	74,634	12,699	6,598	86	100,398
			Sub-Total = 6,381					Sub-Total = 19,383			
		(ii) 0.5 wt.% S, max.	9,683	18	74	-	101,693	12,699	6,598	86	130,851
			Sub-Total = 9,775					Sub-Total = 19,383			
3	Impact of Item 2 on sulfur of			18	74	-		12,699	6,598	86	19,475
				Sub-Total = 92				Sub-Total = 19,383			
@4	Combination of 1 and	2 (i)	6,289	18	74	-	74,634	12,699	6,598	86	100,398
			Sub-Total = 6,381					Sub-Total = 19,383			
		2 (ii)	9,683	18	74	-	101,693	12,699	6,598	86	130,851
			Sub-Total = 9,775					Sub-Total = 19,383			

P Based on Statistics Canada - Refined Petroleum Products '79

@ Same as Item 2

* Incl. interprovincial export/import domestic sales etc. and corrections for losses and inventory changes

● Excl. own consumption but including corrections for losses and inventory changes

** Annual = 325 days per year

4.2.3 Design Capacity for Additional Plants Required, Table 4.2.3

No additional HDS unit would be required for Case 1.

For Cases 2 (i) and 2 (ii), the requirements are shown. The distribution of additional desulfurization and supporting plants are artificial according to crude processing capability of the refinery in question for cost estimation propose. This treatment may not be appropriate based on the possibility that large refineries who are assigned larger units may have already had larger capacity installation.

TABLE 4.2.3

DESIGN CAPACITY FOR ADDITIONAL PLANTS — QUEBEC REGION

Refinery	Crude Capacity BPCD	%	0.5 % Sulfur in HFO				1.0 % Sulfur in HFO				CODE
			* Vacuum Residue HDS BPSD	Ⓑ H Plant 97% 10^6 SCFD	Amine 10^6 SCFD	Ⓟ Sulphur STPD	*Vacuum Residue HDS BPSD	Ⓑ H_2 Plant 97% 10^6 SCFD	Amine 10^6 SCFD	Ⓟ Sulfur STPD	
B.P.	73,000	11.8	7,700	5.9	5.3	34	5,100	2.0	2.8	19	Q-1
Ultramar	100,000	16.2	10,600	8.1	7.3	47	7,000	2.8	3.8	26	Q-2
Gulf	77,300	12.5	8,200	6.3	5.6	36	5,400	2.2	3.0	20	Q-3
Imperial	77,600	12.6	8,200	6.3	5.6	36	5,400	2.2	3.0	20	Q-4
Petrofina	95,000	15.4	10,000	7.6	7.0	45	6,600	2.7	3.6	24	Q-5
Shell	120,000	19.4	12,700	9.6	8.8	56	8,300	3.4	4.6	31	Q-6
Texaco	74,500	12.1	7,900	6.0	5.4	35	5,200	2.1	2.8	19	Q-7
TOTAL	617,400	100.0	65,300	49.8	45.0	289	43,000	17.4	23.6	159	

On Stream Factor 0.89

* Vacuum Residue HDS: HRI H-Oil Process

Ⓑ H_2 Plant Feedstock: Naphtha

Ⓟ Sulfur Recovery 97.5%

4.2.4 Increased Annual Crude Feed Requirements, Table 4.2.4

Based on the same assumption that all refinery production would have to be maintained, including that of HFO and LFO's, the increased crude annually required are shown.

TABLE 4.2.4

INCREASED ANNUAL CRUDE FEED REQUIREMENTS QUEBEC REGION

Simulated Base Case: 1979 Total Crude Oil Requirement
= 29,623,000 M3 or 186,322,000 Bbl. (or 510,472 BPCD■)

Case	Increased Crude Feed / Specification	* Annual Requirements		Daily Requirements
		M3	Bbl.	BPCD
1	#2 Fuel Oil and Lighter, 0.3 wt.% S, max.	36,841	231,725	713
2 (i)	HFO (#4,#5,#6) 1.0 wt.% S, max.	115,381	725,725	2,233
2 (ii)	HFO (#4,#5,#6) 0.5 wt.% S, max.	197,951	1,245,075	3,831
1 + 2 (i)	Combination of case 1 and case 2 (i)	115,381	725,725	2,233
1 + 2 (ii)	Combination of case 1 and case 2 (ii)	197,951	1,245,075	3,831

* Annual = 325 Days Per Year

■ See Simulated Base Case Printout

4.2.5 ANNUAL CHANGE OF REFINERY PRODUCTION DUE TO DESULFURIZATION

4.2.5.1 Prediction of Annual Change of Heavy and Light Fuel Oils Production, Table 4.2.5 (a)

The reduction of HFO and LFO's production because of desulfurization losses is accounted for each new S fuel specification proposed. The reduction was based on the assumption that no additional crude would be required.

4.2.5.2 Prediction of Annual Increase of Fuel Gas, Naphtha and Sulfur Production Due to Desulfurization, Table 4.2.5. (b)

In Cases 2 (i) and 2 (ii), there were sufficient treated naphtha to be used as feedstock to H_2 plants required for the hydro-desulfurization.

TABLE 4.2.5 (a)

PREDICTION OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OILS PRODUCTION DUE TO DESULFURIZATION QUEBEC REGION

Design Basis: Crude Feed = 510,472 BPCD

Item	* Annual Change / Specification		ᵽ Existing Refinery Output	
			Heavy Fuel Oil M Bbl.	Light Fuel Oils (LFO, Diesel Fuel & Stove Oil) M Bbl.
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		- 61	- 79
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S. max.	- 497	- 174
		(ii) 0.5 wt.% S. max.	- 961	- 174
4	Combination of 1 and	2 (i)	- 497	- 174
		2 (ii)	- 961	- 174

* Annual = 325 Days Per Year

ᵽ Including Own Consumption

"+" and "-" denotes increased and decreased production respectively

TABLE 4.2.5 (b)

PREDICTION OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA AND SULFUR PRODUCTION DUE TO RESIDUE DESULFURIZATION QUEBEC REGION

Design Basis: Crude Feed = 510,472 BPCD

Item	* Annual Production Change / Specification		Vacuum Residue HDS		
			Fuel Gas (Gross) M FOEB **	Naphtha (Gross) M Bbl.	Sulfur 97.5% Recovered metric tonne, t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		-	-	-
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S, max.	529	879	41,300
		(ii) 0.5 wt.% S, max.	1,024	1,623	76,100
4	Combination of 1 and	2 (i)	529	879	41,300
		2 (ii)	1,024	1,623	76,100

* Annual = 325 Days Per Year

** FOEB = 6.3×10^6 BTU (Fuel Gas LHV = 600 BTU/SCF)

4.2.6 Increased Annual Energy Requirements, Table 4.2.6

Additional energy requirements in terms of Fuel, Electricity, Steam and Cooling Water for each new S fuel spec are summarized and shown.

Tables 4.2.6 (a) shows the additional energy requirements broken down into individual desulfurization and supporting units for Case 1.

Tables 4.2.6 (b) and (c) show the same for Case 2 (i) and 2 (ii) respectively.

4.2.7 Crude Oil Equivalent of Increased Annual Energy Requirements, Table 4.2.7

The crude oil equivalents barrels of incremental annual energy required are shown in Table 4.2.7. The % of energy consumed in terms of new crude feed (100%) are also shown.

TABLE 4.2.6

INCREASED ANNUAL ENERGY REQUIREMENTS QUEBEC REGION

Case	Increased Energy / Specification	Increased Annual* Energy Requirements				
		Fuel FOEB (10^6 BTU)	Electricity 10^3 kW-h (10^6 BTU)	Steam 10^3 lb. (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	193,248 (1,217,463)	32,339 (323,388)	181,000 (181,000)	2,106	(1,721,851)
2 (i)	HFO (#4, #5, #6) 1.0 wt.% S, max.	652,804 (4,112,664)	172,975 (1,729,738)	2,583,471 (2,583,471)	10,485	(8,425,873)
2 (ii)	HFO (#4, #5, #6) 0.5 wt.% S, max.	1,156,003 (7,282,818)	249,327 (2,493,264)	6,370,800 (6,370,800)	15,355	(16,146,882)
1 + 2 (i) o	Combination of case 1 and case 2 (ii)	652,804 (4,112,664)	172,975 (1,729,738)	2,583,471 (2,583,471)	10,485	(8,425,873)
1 + 2 (ii) •	Combination of case 1 and case 2 (ii)	1,156,003 (7,282,818)	249,329 (2,493,264)	6,370,800 (6,370,800)	15,355	(16,146,882)

* Annual = 325 Days Per Year

** Fuel, 1 FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

o Same as case 2 (i)

• Same as case 2 (ii)

TABLE 4.2.6 (a)

INCREASED ANNUAL ENERGY REQUIREMENTS QUEBEC REGION

Case: 0.3% S HFO (Case 1)

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	193,248 (1,217,463)	32,339 (323,388)	181,000 (181,000)	2,106	(1,721,851)
Vacuum Residue HDS	-	-	-	-	-
Hydrogen	-	-	-	-	-
Amine	-	-	-	-	-
Sulfur	-	-	-	-	-
TOTAL	193,248 (1,217,463)	32,339 (323,388)	181,000 (181,000)	2,106	(1,721,851)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

TABLE 4.2.6 (b)

INCREASED ANNUAL ENERGY REQUIREMENTS QUEBEC REGION

Case: 1% S HFO (Case 1)

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	345,725 (2,178,069)	56,357 (563,566)	352,570 (352,570)	3,700	(3,094,205)
Vacuum Residue HDS	69,210 (436,020)	94,885 (948,847)	119,168 (119,168)	326	(1,504,035)
Hydrogen	237,869 (1,498,575)	3,959 (39,585)	1,894,425 (1,894,425)	2,828	(3,432,585)
Amine	-	16,874 (168,740)	460,200 (460,200)	1,381	(628,940)
Sulfur	-	900 (9,000)	-242,892 (-242,892)	2,250	(-233,892)
TOTAL	652,804 (4,112,664)	172,975 (1,729,738)	2,583,471 (2,583,471)	10,485	(8,425,873)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

• Credit for steam

P All pumps are motor driven p Reboiler heated by steam

TABLE 4.2.6 (c)

INCREASED ANNUAL ENERGY REQUIREMENTS QUEBEC REGION

Case: 0.5 wt.%S HFO (Case 2 (11))

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	345,725 (2,178,069)	56,357 (563,566)	352,570 (352,570)	3,700	(3,094,205)
Vacuum Residue and HDS	129,480 (815,724)	147,827 (1,478,273)	161,015 (161,015)	519	(2,455,012)
Hydrogen	680,798 (4,289,025)	11,330 (113,295)	5,421,975 (5,421,975)	8,093	(9,824,295)
Amine	p -	p 32,175 (321,750)	877,500 (877,500)	2,633	(1,199,250)
Sulfur	-	1,638 (16,380)	• -442,260 (-442,260)	410	(-425,880)
TOTAL	1,156,003 (7,282,818)	249,327 (2,493,264)	6,370,800 (6,370,800)	15,355	(16,146,882)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

• Credit for steam

p All pumps are motor driven p Reboiler heated by steam

TABLE 4.2.7

CRUDE OIL EQUIVALENT OF INCREASED ANNUAL ENERGY REQUIREMENTS — QUEBEC REGION

Case	Specification / Increased Annual*	Energy Requirement 10^6 BTU	Crude Oil Equivalent Bbl	% Energy
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	1,721,851	297,870	0.18 #
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	8,425,873	1,457,630	0.87 ##
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	16,146,882	2,793,320	1.67 ###
1 + 2 (i)	Combination of Case 1 and Case 2(i)	8,425,873	1,457,630	0.87 ##
1 + 2(ii)	Combination of Case 1 and Case 2 (ii)	16,146,882	2,793,320	1.67 ###

Heating Value of Crude = 5,780,530 BTU/Bbl

* Annual = 325 days per year;

\# New Crude Feed, 511,185 BPCD = 100%;

\## New Crude Feed, 512,705 BPCD = 100%

\### New Crude Feed, 514,303 BPCD = 100%

4.3 ONTARIO REGION

4.3.1 Actual & Simulated Sulfur contents of Fuel Oils, Table 4.3.1

Without utilizing any hydrotreater, the simulated base case printouts O-S-B, was performed. The S levels of all fuel oils simulated were lower than that of 1979 Actual data. The results were considered to be reasonable except those of Diesel Fuel and Stove Oil/ Kerosene which would not sufficiently affect the overall S reduction calculation. The fairly good matching of S contents of LFO and Saleable HFO with those of 1979 actual data were considered acceptable. The actual S data of 1979 indicated that LFO's were below 0.3% S and therefore Case 1 specification was met at that time.

In Case 1, printouts O-1, the S content of HFO was slightly decreased and only 5.9% hydrotreater capacity were used, Table 3.1.3.

Case 2 (i), is identical to Case 1, i.e. S content of HFO was 0.936 wt. % and therefore the 1.0 wt. % S in HFO spec. was easily achieved. The ample reserved capacity of hydrotreaters in Ontario was evident, Table 3.1.4.

In Case 2(ii), by only utilizing 12.0 % of installed hydrotreater capacity, Table 3.15 and an additional vacuum resid HDS unit, of 41,100 BPSD, it was possible to decrease the S content of HFO to 0.489 wt. %. Again, the large reserved capacity for distillate and gas oil hydrotreaters was obvious.

TABLE 4.3.1

ACTUAL & SIMULATED SULFUR CONTENT OF FUEL OILS ONTARIO REGION

Item	Sulfur wt.% / Case	Refinery Own Consumption				Saleable	Light Fuel Oils		
		HFO	LFO	Diesel Fuel	Stove Oil/ Kerosene	HFO (#4,#5,#6)	LFO #2	Diesel Fuel	Stove Oil/ Kerosene
A	'79 Actual*	1.246	0.280	0.291	0.092	1.005	0.280	0.291	0.092
S-B	Simulation Base Case	0.957	0.206	0.105	0.058	0.957	0.206	0.105	0.058
1	Simulation #2 Fuel Oil & Lighter 0.3 wt.% S, max.	0.936	0.206	0.105	0.058	0.936	0.206	0.105	0.058
2 (i)	Simulation Heavy Fuel Oil 1.0 wt.% S, max.	0.936	0.206	0.105	0.058	0.936	0.206	0.105	0.058
2(ii)	Simulation Heavy Fuel Oil 0.5 wt.% S, max.	0.489	0.206	0.105	0.058	0.489	0.206	0.105	0.058

* APCD, Environment Canada, Dec. '79 Data

4.3.2 Prediction of Annual Sulfur Reduction of Fuels, Table 4.3.2

In any single case or combination case, S reduction in HFO and LFO was evidently shown. Due to the lower "actual" S present in every fuel oil (except that in stove oil/kerosene) in Ontario, Table 4.3.1, the S reduction was not as significant as that in the other three regions. Nevertheless, for Case 1 or Case 2 (i) and Case 2 (ii) a total of 14,443 t and 40,985 t of sulfur could be further reduced respectively.

TABLE 4.3.2

PREDICTION OF ANNUAL SULFUR REDUCTION IN FUELS ONTARIO REGION

Item	Specifications / ** Annual S Reduction		(A) P Refinery Own Fuel Consumption HFO t	Light Fuel Oils LFO t	Diesel t	Stove Oil t	(B) P * Saleable HFO (#4, #5, #6) t	(C) P • Light Fuel Oil Products LFO t	Diesel t	Stove Oil t	(A)+(B)+(C) TOTAL metric tonne t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		2,753	10	40	-	3,485	3,287	4,813	55	14,443
			Sub-Total = 2,803					Sub-Total = 8,155			
2	HFO (#4, #5, #6)	(I) 1.0 wt.% S, max.	2,753	10	40	-	3,485	3,287	4,813	55	14,443
			Sub-Total = 2,803					Sub-Total = 8,155			
		(II) .05 wt.% S, max.	6,722	10	40	-	26,058	3,287	4,813	55	40,985
			Sub-Total = 6,772					Sub-Total = 8,155			
3	Impact of item 2 on sulfur of		-	10	40	-		3,287	4,813	55	8,205
			Sub-Total = 50					Sub-Total = 8,155			
B4	Combination of 1 and	2 (I)	2,753	10	40	-	3,485	3,287	4,813	55	14,443
			Sub-Total = 2,803					Sub-Total = 8,155			
		2 (II)	6,722	10	40	-	26,058	3,287	4,813	55	40,985
			Sub-Total = 6,772					Sub-Total = 8,155			

P Based on Statistics Canada - Refined Petroleum Products '79

B Same as Item 2

* Incl. interprovincial export/import domestic sales etc. and corrections for losses and inventory changes

• Excl. own consumption but including corrections for losses and inventory changes

** Annual = 325 days per year

4.3.3. Design Capacity for Additional Plants Required, Table 4.3.3

No additional desulfurization unit would be required for Case 1 and Case 2 (i).

No additional H_2 plant would be added to hydrodesulfurization fuel oils to meet Case 2 (ii) sulfur specification.

TABLE 4.3.3

DESIGN CAPACITY FOR ADDITIONAL PLANTS ONTARIO REGION

Refinery	Crude Capacity	%	0.5 wt. % Sulfur in HFO				** 1.0 wt. % Sulfur in HFO				CODE
			* Vacuum Residue HDS BPSD	@ H_2 Plant 97% 10^6 SCFD	Amine 10^6 SCFD	Sulfur STPD	* Vacuum Residue HDS BPSD	@ H_2 Plant 97% 10^6 SCFD	Amine 10^6 SCFD	Sulfur STPD	
B.P.	80,000	10.6	4,400		3.0	10					0-1
Gulf	79,100	10.4	4,300		3.0	10					0-2
Imperial	126,100	16.6	6,800		4.6	16					0-3
Petrosar	170,000	22.4	9,200		6.3	21					0-4
Shell (Oakville)	44,000	5.8	2,400		1.6	6					0-5
Shell (Sarnia)	74,000	9.8	4,000		2.7	9					0-6
Suncor	90,000	11.9	4,900		3.3	11					0-7
Texaco (Nanticoke)	95,000	12.5	5,100		3.5	12					0-8
TOTALS	758,200	100.0	41,100	-	28.0	95	-	-	-	-	

On Stream Factor 0.89

* Vacuum Residue HDS: HRI H-Oil Process

@ No Additional H_2 Plant Required

· Sulfur Recovery = 97.5%

** No Additional Hyrotreaters and Supporting Plants Required

4.3.4 Increased Annual Crude Feed Requirements, Table 4.3.4

The additional crude feed requirements for Case 1 and Case 2 (i) are negligible. However, the annual requirements for 2 (ii) are substantial.

TABLE 4.3.4

INCREASED ANNUAL CRUDE FEED REQUIREMENTS ONTARIO REGION

Simulated Base Case: 1979 Total Crude Oil Requirement
= 35,117,000 M^3 or 220,878,000 Bbl. (or 605,146 BPCD■)

Case	Increased Crude Feed Specifications	* Annual Requirements		Daily Requirements BPCD
		M^3	Bbl.	
1	#2 Fuel Oil and Lighter, 0.3 wt.% S, max.	3,927	24,700	76
2 (i)	HFO (#4,#5,#6) 1.0 wt.% S, max.	3,927	24,700	76
2 (ii)	HFO (#4,#5,#6) 0.5 wt.% S, max.	176,869	1,112,475	3,423
1 + 2 (i)	Combination of case 1 and case 2 (i)	3,927	24,700	76
1 + 2 (ii)	Combination of case 1 and case 2 (ii)	176,869	1,112,475	3,423

* Annual = 325 Days Per Year

■ See Simulated Base Case Printout

4.3.5 ANNUAL CHANGE OF REFINERY PRODUCTION DUE TO DESULFURIZATION

4.3.5.1 Prediction of Annual Change of Heavy and Light Fuel Oils Production, Table 4.3.5 (a)

There was no LFO's change in all three new S fuel specifications. The change in HFO production in Case 1 and Case 2 (ii) was minimal.

4.3.5.2 Prediction of Annual Increase of Fuel Gas, Naphtha and Sulfur Production Due to Residue Desulfurization, Table 4.3.5 (b)

Since no additional residue desulfurization would be needed to meet the S specification in 2 (i), no production for fuel gas naphtha and sulfur are shown.

Since no H_2 plant would be required in any of the cases, all treated naphtha produced by Case 2 (ii) can possibly be used in the refinery for other purposes or for export.

TABLE 4.3.5 (a)

PREDICTION OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OILS PRODUCTION DUE TO DESULFURIZATION ONTARIO REGION

Design Basis: Crude Feed = 605,146 BPCD

Item	Specification	* Annual Change	p Existing Refinery Output: Heavy Fuel Oil M Bbl.	p Existing Refinery Output: Light Fuel Oils (LFO, Diesel Fuel & Stove Oil) M Bbl.
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		- 24	
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S. max.	- 24	
		(ii) 0.5 wt.% S. max.	- 985	
4	Combination of 1 and	2 (i)	- 24	
		2 (ii)	- 985	

* Annual = 325 Days Per Year

p Including Own Consumption

"+" and "-" denotes increased and decreased production respectively

TABLE 4.3.5 (b)

PREDICTION OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA AND SULFUR PRODUCTION DUE TO RESIDUE DESULFURIZATION ONTARIO REGION

Design Basis: Crude Feed = 605,146 BPCD

Item	* Annual Production Change / Specification		Vacuum Residue HDS		
			Fuel Gas (Gross) M FOEB **	Naphtha (Gross) M Bbl.	Sulfur 97.5% Recovered metric tonne, t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		-	-	-
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S, max.	-	-	-
		(ii) 0.5 wt.% S, max.	743	1,071	21,829
4	Combination of 1 and	2 (i)	-	-	-
		2 (ii)	743	1,071	21,829

* Annual = 325 Days Per Year

** FOED = 6.3×10^6 BTU (Fuel Gas LHV = 600 BTU/SCF)

4.3.6 Increased Annual Energy Requirements, Table 4.3.6

There was a surplus steam produced in Case 2 (ii), Table 4.3.6 (c), which would be credited to the operating costs as to be discussed in 5.2.

4.3.7 Crude Oil Equivalent of Increased Annual Energy Requirements, Table 4.3.7

The crude oil equivalent barrels of incremental annual energy required are shown in Table 4.3.7. They are also expressed in terms of new crude feed (100%).

TABLE 4.3.6

INCREASED ANNUAL ENERGY REQUIREMENTS ONTARIO REGION

Case	Increased Energy / Specification	Increased Annual* Energy Requirements				
		Fuel FOEB (10^6 BTU)	Electricity 10^3 kW-h (10^6 BTU)	Steam 10^3 lb. (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
2 (i)	HFO (#4, #5, #6) 1.0 wt.% S, max.	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
2 (ii)	HFO (#4, #5, #6) 0.5 wt.% S, max.	113,358 (714,153)	122,598 (1,225,979)	■ -47,408 (-47,408)	740	(1,892,724)
1 + 2 (i)	combination of case 1 and case 2 (ii)	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
1 + 2 (ii)	combination of case 1 and case 2 (ii)	113,358 (714,153)	122,598 (1,225,979)	■ -47,408 (-47,408)	740	(1,892,724)

* Annual = 325 Days Per Year

** Fuel, 1 FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

o Same as case 2 (i)

• Same as case 2 (ii)

■ Credit for steam

TABLE 4.3.6 (a)

INCREASED ANNUAL ENERGY REQUIREMENTS ONTARIO REGION

Case: 0.3% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
Vacuum Residue HDS	-	-	-	-	-
Hydrogen	-	-	-	-	-
Amine	-	-	-	-	-
Sulfur	-	-	-	-	-
TOTAL	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

TABLE 4.3.6 (b)

INCREASED ANNUAL ENERGY REQUIREMENTS ONTARIO REGION

Case: 1: S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
Vacuum Residue HDS	-	-	-	-	-
Hydrogen	-	-	-	-	-
Amine	-	-	-	-	-
Sulfur	-	-	-	-	-
TOTAL	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

e Credit for steam

P All pumps are motor driven

p Reboiler heated by steam

TABLE 4.3.6 (c)

INCREASED ANNUAL ENERGY REQUIREMENTS ONTARIO REGION

Case: 0.5% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	4,740 (29,860)	3,682 (36,827)	17,426 (17,426)	167	(84,113)
Vacuum Residue HDS	108,618 (684,293)	118,098 (1,180,975)	101,304 (101,304)	402	(1,966,572)
Hydrogen	-	-	-	-	-
Amine	p -	p 200 (2,002)	592 (592)	17	(2,594)
Sulfur	-	618 (6,175)	• -166,730 (-166,730)	154	(-160,555)
TOTAL	113,358 (714,153)	122,598 (1,225,979)	• -47,408 (-47,408)	740	(1,892,724)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

• Credit for steam

p All pumps are motor driven p Reboiler heated by steam

TABLE 4.3.7

CRUDE OIL EQUIVALENT OF INCREASED ANNUAL ENERGY REQUIREMENTS — ONTARIO REGION

Case	Increased Annual* Specification	Energy Requirement 10^6 BTU	Crude Oil Equivalent Bbl	% Energy
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	42,056	7,430	0.004 #
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	42,056	7,430	0.004 ##
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	1,892,724	334,270	0.17 ###
1 + 2 (i)	Combination of Case 1 and Case 2(i)	42,056	7,430	0.004 ##
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	1,892,724	334,270	0.17 ###

Heating Value of Crude = 5,662,195 BTU/Bbl

* Annual = 325 days per year;

New Crude Feed, 605,223 BPCD = 100%;

New Crude Feed, 605,223 BPCD = 100%

New Crude Feed,608,570 BPCD = 100%

4.4 WESTERN REGION

4.4.1 Actual and Simulated Sulfur Contents of Fuel Oils, Table 4.4.1

Due to incomplete sulfur data reported in 1979, the S content of HFO and that of Diesel Fuel originated from the simulated base case, printouts W-S-B, were used for 1979 Actual. However, by comparing the HFO S content used, 2.472 wt. %, with that calculated from a 1978 report (Reference 10), 3.006 wt. %, the data used was considered low but much more reasonable than those calculated, 0.981 wt. % for refinery own HFO and 1.243 wt. % for Saleable HFO, from the APCD printout (Reference 7). The % utilization of installed hydrotreater capacity for 1979 was estimated at 86.1 %, Table 3.1.2.

In Case 1, by using 95.5 % installed hydrotreater capacity, Table 3.1.3, the S content of HFO was simultaneously raised slightly to 2.481. This simulation indicates the undesirable but possible change of S level in HFO.

In Case 2 (i), the S level of HFO was successfully lowered to 0.992 wt. % by 100% utilization of the existing hydrotreater capacity, Table 3.1.4, plus an additional 19,500 BPSD vacuum resid HDS unit. at the same time the S contents of LFO and that of Diesel Fuel were also decreased to 0.255 wt. % and 0.239 wt. % respectively

In Case 2 (ii), by using 100% installed hydrotreater capacity, Table 3.1.5, plus an additional 25,700 BPSD vacuum resid HDS unit, it was possible to reduce the S content of HFO to 0.525 wt. %. Further reduction would require a marginal increase of HCO hydrodesulfurization capacity.

TABLE 4.4.1

ACTUAL & SIMULATED SULFUR CONTENT OF FUEL OILS WESTERN REGION

Item	Case \ Sulfur wt.%	Refinery Own Consumption				Saleable	Light Fuel Oils		
		HFO	LFO	Diesel Fuel	Stove Oil/ Kerosene	HFO (#4,#5,#6)	LFO #2	Diesel Fuel	Stove Oil/ Kerosene
A	'79 Actual	**2.472	*0.346	**0.319	*0.077	**2.472	*0.346	*0.319	*0.077
S-B	Simulation Base Case	2.472	0.345	0.319	0.077	2.472	0.345	0.319	0.077
1	Simulation #2 Fuel Oil & Lighter 0.3 wt.% S, max.	2.481	0.295	0.273	0.077	2.481	0.295	0.273	0.077
2 (i)	Simulation Heavy Fuel Oil 1.0 wt.% S, max.	0.992	0.255	0.239	0.077	0.992	0.255	0.239	0.077
2(ii)	Simulation Heavy Fuel Oil 0.5 wt.% S, max.	0.525	0.255	0.239	0.077	0.525	0.255	0.239	0.077

* Based on APCD, Environment Canada, Dec. '79 incomplete data

** Using data from simulated base case

4.4.2 Prediction of Annual Sulfur Reduction in Fuels, Table 4.4.2

The saleable HFO shows an increase of S of 192 t per annum in Case 1. This is because of the uncertainty of S content data of HFO in 1979 Actual case as discussed in 4.4.1. However, it would not affect the overall result significantly.

TABLE 4.4.2

PREDICTION OF ANNUAL SULFUR REDUCTION IN FUELS WESTERN REGION

Item	Specification	** Annual S Reduction	(A) P Refinery Own Fuel Consumption				(B) P* Saleable	(C) P• Light Fuel Oil Products			(A)+(B)+(C) TOTAL
			HFO	Light Fuel Oils			HFO (#4, #5, #6)	LFO	Diesel	Stove Oil	metric tonne
			t	LFO t	Diesel t	Stove Oil t	t	t	t	t	t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, Max.		-8	-	5	-	-192	681	2,752	-	3,238
			Sub-Total = -3					Sub-Total = 3,433			
2	HFO (#4, #5, #6)	(i) 1.0 wt.% S, max.	1,340	-	8	-	33,120	1,214	4,787	-	40,469
			Sub-Total = 1,348					Sub-Total = 6,001			
		(ii) 0.5 wt.% S, max.	1,762	-	8	-	41,439	1,214	4,787	-	49,210
			Sub-Total = 1,770					Sub-Total = 6,001			
3	Impact on Item 2 on sulfur of			-	8	-		1,214	4,787	-	6,009
			Sub-Total = 8					Sub-Total = 6,001			
4	Combination of 1 and	2 (i)	1,340	-	8	-	33,120	1,214	4,787	-	40,469
			Sub-Total = 1,348					Sub-Total = 6,001			
		2 (ii)	1,762	-	8	-	41,439	1,214	4,787	-	49,210
			Sub-Total = 1,770					Sub-Total = 6,001			

P Based on Statistics Canada - Refined Petroleum Products '79

8 Same as Item 2

* Incl. interprovincial export/import domestic sales etc. and corrections for losses and inventory changes

• Excl. own consumption but including corrections for losses and inventory changes

** Annual = 325 days per year

4.4.3 Design Capacity for Additional Plants Required, Table 4.4.3

No additional desulfurization unit would be required for Case 1.

No additional H_2 plants will be needed for Case 2 (i) and 2 (ii).

The breakdown of a composite refinery of amine and sulfur plants into smaller capacities may not be practical but for the reasons of having a cost estimation for each refinery, as required. The installed capacity of hydrotreaters were and would be fully utilized in this region. The requirement for additional gas oil hydrotreater - to exactly meet the Case 2 (ii) S specification is marginal.

TABLE 4.4.3

DESIGN CAPACITY FOR ADDITIONAL PLANTS REQUIRED WESTERN REGION

Refinery	Crude Capacity BPCD	%	0.5 % Sulfur in HFO				1.0 % Sulfur in HFO				CODE
			*Vacuum Residue HDS BPSD	@ H_2 Plant 97% 10^6 SCFD	Amine 10^6 SCFD	ℙ Sulfur STPD	*Vacuum Residue HDS BPSD	@ H_2 Plant 97% 10^6 SCFD	Amine 10^6 SCFD	ℙ Sulfur STPD	
Chevron	35,000	6.5	1600	-	2.5	16	1200	-	2.1	14	W-1
Gulf, Kamloops	9,300	1.7	500	-	1.0	5	400	-	1.0	5	W-2
Gulf, Port Moody	37,200	7.0	1700	-	2.7	18	1300	-	2.2	15	W-3
Husky, Pr. George	10,000	1.9	500	-	1.0	5	400	-	1.0	5	W-4
Imperial, Ioco	40,700	7.6	1900	-	2.9	19	1400	-	2.4	16	W-5
Petro Can	14,300	2.7	700	-	1.0	7	500	-	1.0	6	W-6
Shell, Burnaby	22,000	4.1	1000	-	1.6	10	800	-	1.3	9	W-7
Gulf, Calgary	8,700	1.6	400	-	1.0	5	300	-	1.0	5	W-8
Gulf, Edmonton	80,000	15.0	3600	-	5.7	38	2700	-	4.8	32	W-9
Husky, Llymr.	12,000	2.2	600	-	1.0	6	400	-	1.0	5	W-10
Imperial, Edm.	150,000	28.2	6800	-	10.7	71	5100	-	9.0	61	W-11
Shell, Bowden	5,000	0.9	300	-	1.0	5	200	-	1.0	5	W-12
Texaco	24,000	4.5	1100	-	1.7	11	900	-	1.4	10	W-13
Consumers' Co-op	40,000	7.5	1800	-	2.9	19	1400	-	2.4	16	W-14
Gulf, Moose Jaw	13,300	7.5	1800	-	2.9	19	1400	-	2.4	16	W-15
Shell, St. Boniface	30,000	5.6	1400	-	2.1	14	1100	-	1.8	12	W-16
Imperial, N. Wells	2,900	0.5	-	-	-	-	-	-	-	-	W-17
TOTAL	535,000	100.0	25,700	-	41.7	268	19,500	-	35.8	232	

* Vacuum Residue HDS: HRI H-Oil Process

@ No additional H_2 Plant required

ℙ Sulfur Recovery 97.5%

On Stream Factor = 0.89

4.4.4 Increased Annual Crude Feed Requirements, Table 4.4.4

The incremental crude feed required, 222 BPCD, for Case 1 are marginal if not negligible. However, the annual requirements for Case 2(i) and 2(ii) are accountable.

TABLE 4.4.4

INCREASED ANNUAL CRUDE FEED REQUIREMENTS WESTERN REGION

Simulated Base Case: 1979 Total Crude Oil Requirement
= 30,490,000 M^3 or 191,778,000 Bbl. (or 525,420 BPCD■)

Case	Increased Crude Feed Requirements	* Annual Requirements		Daily Requirements
		M^3	Bbl.	BPCD
1	#2 Fuel Oil and Lighter, 0.3 wt.% S, max.	11,471	72,150	222
2 (i)	HFO (#4,#5,#6) 1.0 wt.% S, max.	59,422	373,750	1,150
2(ii)	HFO (#4,#5,#6) 0.5 wt.% S, max.	107,785	677,950	2,086
1 +2 (i)	Combination of case 1 and case 2 (i)	59,422	373,750	1,150
1 +2 (ii)	Combination of case 1 and case 2 (ii)	107,785	677,950	2,086

* Annual = 325 Days Per Year

■ See Simulated Base Case Printout

4.4.5 ANNUAL CHANGE OF REFINERY PRODUCTION

4.4.5.1 Annual Change of Heavy and Light Fuel Oils Due to Desulfurization, Table 4.4.5 (a)

There were some marginal increases in the LFO's production for Case 2 (i) and (ii).

The reduced production of HFO and LFO's in Case (i) can be neglected.

4.4.5.2 Annual Increase of Fuel Gas Naphtha & Sulfur Production Due to Resid Desulfurization, Table 4.4.5 (b)

Since there would not be additional H_2 plants required for Case 2 (i) and (ii), all the naphtha and fuel gas produced as a result of vacuum resid HDS could be used in the refinery as fuels or other purposes or for export.

TABLE 4.4.5 (a)

PREDICTION OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OILS PRODUCTION DUE TO DESULFURIZATION WESTERN REGION

Design Basis: Crude Feed = 525,420 BPCD

Item	* Annual Change / Specification		ᵽ Existing Refinery Output	
			Heavy Fuel Oil M Bbl.	Light Fuel Oils (LFO, Diesel Fuel & Stove Oil) M Bbl.
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		- 51	- 18
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S. max.	- 247	+ 22
		(ii) 0.5 wt.% S. max.	- 515	+ 22
4	Combination of 1 and	2 (i)	- 247	+ 22
		2 (ii)	- 515	+ 22

* Annual = 325 Days Per Year

ᵽ Including Own Consumption

"+" and "-" denotes increased and decreased production respectively

TABLE 4.4.5 (b)

PREDICTION OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA AND SULFUR PRODUCTION DUE TO RESIDUE DESULFURIZATION WESTERN REGION

Design Basis: Crude Feed = 525,420 BPCD

Item	* Annual Production Change / Specification		Vacuum Residue HDS		
			Fuel Gas (Gross) M FOEB **	Naphtha (Gross) M Bbl.	Sulfur 97.5% Recovered metric tonne, t
1	#2 Fuel Oil & Lighter 0.3 wt.% S, max.		-	-	-
2	HFO (#4,#5,#6)	(i) 1.0 wt.% S, max.	241	365	27,890
		(ii) 0.5 wt.% S, max.	387	812	37,187
4	Combination of 1 and	2 (i)	241	365	27,890
		2 (ii)	387	812	37,187

* Annual = 325 Days Per Year

** FOEB = 6.3×10^6 BTU (Fuel Gas LHV = 600 BTU/SCF)

4.4.6 Increased Annual Energy Requirements, Table 4.4.6

There was a surplus steam, originated from the sulfur plants, Table 4.4.6 (b) and (c), which amounted to approximately one third of the total energy required, would be credited to the operating costs as to be discussed in 5.2.

4.4.7 Crude Oil Equivalent of Increased Annual Energy Requirements, Table 4.4.7

The result of converting increased annual energy requirements i.e. Table 4.4.6 excluding cooling water, to crude oil equivalent barrels are shown in Table 4.4.7. The % of energy consumed in terms of new crude feed (100%) are also included.

TABLE 4.4.6

INCREASED ANNUAL ENERGY REQUIREMENTS WESTERN REGION

Case	Increased Energy / Specification	Increased Annual* Energy Requirements				
		Fuel FOEB (10^6 BTU)	Electricity 10^3 kW-h (10^6 BTU)	Steam 10^3 lb. (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	34,503 (217,368)	5,434 (54,340)	38,816 (38,816)	361	(310,524)
2 (i)	HFO (#4, #5, #6) 1.0 wt.% S, max.	70,833 (446,250)	41,463 (414,628)	@ -311,616 (-311,616)	1,019	(549,262)
2 (ii)	HFO (#4, #5, #6) 0.5 wt.% S, max.	72,148 (454,534)	62,295 (622,947)	@ -363,290 (-363,290)	1,151	(714,191)
o 1 + 2 (i)	Combination of case 1 and case 2 (ii)	70,833 (446,250)	41,463 (414,628)	@ -311,616 (-311,616)	1,019	(549,262)
• 1 + 2 (ii)	Combination of case 1 and case 2 (ii)	72,148 (454,534)	62,295 (622,947)	@ -363,290 (-363,290)	1,151	(714,191)

* Annual = 325 Days Per Year

** Fuel, 1 FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

o Same as case 2 (i)

• Same as case 2 (ii)

@ Credit for steam

TABLE 4.4.6 (a)

INCREASED ANNUAL ENERGY REQUIREMENTS WESTERN REGION

Case: 0.3% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling Water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	34,503 (217,368)	5,434 (54,340)	38,816 (38,816)	361	(310,524)
Vacuum Residue HDS	-	-	-	-	-
Hydrogen	-	-	-	-	-
Amine	-	-	-	-	-
Sulfur	-	-	-	-	-
TOTAL	34,503 (217,368)	5,434 (54,340)	38,816 (38,816)	361	(310,524)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 10^6 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

TABLE 4.4.6 (b)

INCREASED ANNUAL ENERGY REQUIREMENTS WESTERN REGION

Case: 1% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	51,110 (321,993)	8,050 (80,500)	57,499 (57,499)	535	(459,992)
Vacuum Residue HDS	19,723 (124,257)	31,649 (316,488)	31,064 (31,064)	86	(471,809)
Hydrogen	-	-	-	-	-
Amine	P -	p 256 (2,560)	6,981 (6,981)	21	(9,541)
Sulfur	-	1,508 (15,080)	• -407,160 (-407,160)	377	(-392,080)
TOTAL	70,833 (446,250)	41,463 (414,628)	• -311,616 (-311,616)	1,019	(549,262)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

• Credit for steam

P All pumps are motor driven p Reboiler heated by steam

TABLE 4.4.6 (c)

INCREASED ANNUAL ENERGY REQUIREMENTS WESTERN REGION

Case: 0.5% S HFO

Increased Energy *Annual / Unit	Fuel FOEB ** (10^6 BTU)	Electricity 10^3 kW-h ** (10^6 BTU)	Steam 10^3 lb. ** (10^6 BTU)	Cooling water 10^6 US Gallon	** TOTAL Fuel+Electricity+Steam (10^6 BTU)
Distillate and Gas Oil HTU's	51,110 (321,993)	8,050 (80,500)	57,499 (57,499)	535	(459,992)
Vacuum Residue HDS	21,038 (132,541)	52,205 (522,045)	41,419 (41,419)	156	(696,005)
Hydrogen	-	-	-	-	-
Amine	p -	p 298 (2,982)	8,132 (8,132)	24	(11,114)
Sulfur	-	1,742 (17,420)	e -470,340 (-470,340)	436	(-452,920)
TOTAL	72,148 (454,534)	62,295 (622,947)	e -363,290 (-363,290)	1,151	(714,191)

* Annual = 325 Days Per Year

** Fuel, FOEB = 6.3 x 106 BTU; Electricity, 1 kW-h = 10,000 BTU; Steam, 1 lb. = 1,000 BTU

e Credit for steam

p All pumps are motor driven p Reboiler heated by steam

TABLE 4.4.7

CRUDE OIL EQUIVALENT OF INCREASED ANNUAL ENERGY REQUIREMENTS — WESTERN REGION

Case	Increased Annual* / Specification	Energy Requirement 10^6 BTU	Crude Oil Equivalent Bbl	% Energy
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	310,524	54,770	0.03 #
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	549,262	96,880	0.06 ##
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	714,191	125,970	0.07 ###
1 + 2 (i)	Combination of Case 1 and Case 2(i)	549,262	96,880	0.06 ##
1 + 2 (ii)	Combination of Case 1 and Case 2(ii)	714,191	125,970	0.07 ###

Heating Value of Crude = 5,669,475 BTU/Bbl

* Annual = 325 days per year;

\# New Crude Feed, 525,642 BPCD = 100%;

\## New Crude Feed, 526,570 BPCD = 100%;

\### New Crude Feed, 527,506 BPCD = 100%

5. CAPITAL INVESTMENT AND OPERATING COSTS

5.1 Capital Investment Costs

5.1.1 ATLANTIC REGION

The estimated capital investment costs for Atlantic region are presented in the following tables:

Table 5.1.1.1, Estimate Summary (1.0% S in HFO)

Table 5.1.1.2, Estimate Summary (0.5% S in HFO)

Tables 5.1.1.3 (a) to (e) inclusive, Estimate Detail

TABLE 5.1.1.1

ESTIMATE SUMMARY - (1.0% in HFO)

ATLANTIC REGION

All $ in x 1000

REFINERY #	REFINERY OWNER	REFINERY LOCATION	VAC.RESID. HDS.CAP.COST	ATM.RESID. HDS.CAP.COST	H2 PLANT CAP.COST	AMINE CAP.COST	SULPHUR CAP.COST	TOTAL CAPITAL INVESTMENT
A1	Ultramar	Holyroad	39,450*	14,300*	18,730	2,750	5,200	80,430
A2	Gulf	Pt.Tupper	55,030	14,200	41,290	6,110	11,835	128,465
A3	Imperial	Dartmouth	50,510	13,110	39,240	5,835	11,270	119,965
A4	Texaco	Halifax	35,260*	13,240*	17,050	2,565	5,670	73,785
A5	Irving	St.John	53,780	32,560	83,430	12,730	25,390**	207,890
			234,030	87,410	199,740	29,990	59,365	610,535

* See 2.12.2, Pricing Basis

** Including Tail Gas Clean Up

TABLE 5.1.1.2

ESTIMATE SUMMARY - (0.5% S in HFO)

ATLANTIC REGION

All $ x 1000

REFINERY #	REFINERY OWNER	REFINERY LOCATION	VAC.RESID. HDS.CAP.COST	ATMOS.RESID. HDS.CAP.COST	H2 PLANT CAP.COST	AMINE CAP.COST	SULFUR CAP.COST	TOTAL CAPITAL INVESTMENT
A1	Ultramar	Holyroad	39,550 *	14,390*	18,730	2,890	5,625	81,185
A2	Gulf	Pt.Tupper	55,030	14,270	48,550	6,880	16,000**	140,730
A3	Imperial	Dartmouth	56,890	13,160	45,250	6,740	15,750**	137,790
A4	Texaco	Halifax	35,460*	13,310*	17,060	2,610	6,090	74,530
A5	Irving	St.John	100,940	32,710	99,660	14,200	28,370**	275,880
			287,870	87,840	229,250	33,320	71,835	710,115

* See sect. 2.12.2, Pricing Basis

** Includes Tail Gas Clean Up

REF. # A-1
REF. OWNER Ultramar
REF. LOC. Holyrood

TABLE 5.1.1.3 (a)
ESTIMATE DETAIL

all $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID.				
1. New Equipment	8,620		8,620	
2. Labour & Material	22,990		22,990	
3. Offsites, etc.	1,770		1,680	
Direct Costs		33,380		33,290
ATMOS. RESID.				
1. New Equipment	3,990		3,899	
2. Labour & Material	7,225		7,215	
3. Offsites, etc.	1,315		1,336	
Direct Costs		12,530		12,450
H2 PLANT				
1. New Equipment	5,264		5,264	
2. Labour & Material	8,161		8,161	
3. Offsites, etc.	2,415		2,415	
Direct Costs		15,840		15,840
AMINE				
1. New Equipment	725		726	
2. Labour & Material	1,325		1,280	
3. Offsites, etc.	400		364	
Direct Costs		2,450		2,370
SULPHUR				
1. New Equipment	1,949		1,815	
2. Labour & Material	2,411		2,211	
3. Offsites, etc.	520		484	
Direct Costs		4,880		4,510
TOTAL DIRECT COSTS		69,080		68,460
H.O. ENGINEERING COST		9,660		9,530
CATALYST COST		2,445		2,440
TOTAL CAPITAL INVESTMENT		81,185		80,430

REF. # A2
REF. OWNER Gulf
REF. LOC. Pt. Tupper

TABLE 5.1.1.3 (b)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO	1.0% S in HFO
VAC. RESID.		
1. New Equipment	12,385	13,280
2. Labour & Material	30,492	30,780
3. Offsites, etc.	3,713	2,720
Direct Costs	46,590	46,780
ATMOS. RESID.		
1. New Equipment	3,430	3,360
2. Labour & Material	6,450	6,470
3. Offsites, etc.	2.340	2,330
Direct Costs	12,220	12,160
H2 PLANT		
1. New Equipment	13,610	11,521
2. Labour & Material	21,545	18,079
3. Offsites, etc.	5,885	5,320
Direct Costs	41,040	34,920
AMINE		
1. New Equipment	1,770	1,571
2. Labour & Material	3,160	2,809
3. Offsites, etc.	890	790
Direct Costs	5,820	5,170
SULPHUR		
1. New Equipment	4,967	4,038
2. Labour & Material	7,751	5,124
3. Offsites, etc.	1,202	1,100
Direct Costs	13,920*	10,262
TOTAL DIRECT COSTS	119,590	109,292
H.O. ENGINEERING COST	16,940	15,536
CATALYST COST	4,200	3,637
TOTAL CAPITAL INVESTMENT	140,730	128,465

* Includes Tail Gas Cleanup

REF. # A-3
REF. OWNER Imperial
REF. LOC. Dartmouth

TABLE 5.1.1.3 (c)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID.				
1. New Equipment	15,690		13,400	
2. Labour & Material	29,610		26,980	
3. Offsites, etc.	2,890		2,440	
Direct Costs		48,190		42,820
ATMOS. RESID.				
1. New Equipment	3,440		3,400	
2. Labour & Material	5,730		5,720	
3. Offsites, etc.	2,100		2,100	
Direct Costs		11,270		11,220
H2 PLANT				
1. New Equipment	14,065		11,790	
2. Labour & Material	18,915		15,845	
3. Offsites, etc.	5,270		4,965	
Direct Costs		38,250		32,600
AMINE				
1. New Equipment	1,815		1,634	
2. Labour & Material	3,015		2,551	
3. Offsites, etc.	870		750	
Direct Costs		5,700		4,935
SULPHUR				
1. New Equipment	5,565		4,226	
2. Labour & Material	7,015		4,500	
3. Offsites, etc.	1,110		1,044	
Direct Costs		13,690*		9,770
TOTAL DIRECT COSTS	117,100		101,345	
H.O. ENGINEERING COST	16,570		15,110	
CATALYST COST	4,120		3,510	
TOTAL CAPITAL INVESTMENT		137,790		119,965

* [redacted] Classification

TABLE 5.11.3 (d)

ESTIMATE DETAIL

REF. # A-4
REF. OWNER Texaco
REF. LOC. Halifax

All $ x 1000

	0.5% in HFO		1.0% in HFO	
VAC. RESID.				
1. New Equipment	8,620		8,620	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,680		1,510	
Direct Costs		29,790		29,620
ATMOS. RESID.				
1. New Equipment	3,910		3,899	
2. Labour & Material	6,375		6,365	
3. Offsites, etc.	1,305		1,256	
Direct Costs		11,590		11,520
H2 PLANT				
1. New Equipment	5,264		5,264	
2. Labour & Material	6,961		6,961	
3. Offsites, etc.	2,205		2,195	
Direct Costs		14,430		14,420
AMINE				
1. New Equipment	725		726	
2. Labour & Material	1,145		1,109	
3. Offsites, etc.	340		340	
Direct Costs		2,210		2,175
SULFUR				
1. New Equipment	2,275		2,130	
2. Labour & Material	2,443		2,260	
3. Offsites, etc.	562		526	
Direct Costs		5,280		4,916
TOTAL DIRECT COSTS		63,300		62,651
H.O. ENGINEERING COST		8,860		8,758
CATALYST COST		2,370		2,376
TOTAL CAPITAL INVESTMENT		74,530		73,785

REF. # A-5
REF. OWNER Irving
REF. LOC. St.John

TABLE 5.1.1.3. (e)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID.				
1. New Equipment	29,030		14,520	
2. Labour & Material	49,110		27,000	
3. Offsites, etc.	4,780		3,460	
Direct Costs		82,920		44,980
ATMOS. RESID.				
1. New Equipment	8,440		8,350	
2. Labour & Material	13,830		13,770	
3. Offsites, etc.	5,740		5,740	
Direct Costs		28,010		27,860
H2 PLANT				
1. New Equipment	30,405		24,855	
2. Labour & Material	42,225		35,950	
3. Offsites, etc.	11,610		9,715	
Direct Costs		84,240		70,520
AMINE				
1. New Equipment	3,795		3,630	
2. Labour & Material	6,385		5,650	
3. Offsites, etc.	1,830		1,480	
Direct Costs		12,010		10,760
SULPHUR				
1. New Equipment	9,632		8,790	
2. Labour & Material	12,754		11,420	
3. Offsites, etc.	2,054		1,870	
Direct Costs		24,440*		22,080*
TOTAL DIRECT COSTS		231,620		176,200
H.O. ENGINEERING COST		34,910		26,246
CATALYST COST		9,350		6,444
TOTAL CAPITAL INVESTMENT		275,880		207,890 207,890

*Includes Tail Clean-Up

5.1.2 QUEBEC REGION

The capital investment cost estimations for Quebec region are presented in the following tables:

Table 5.1.2.1, Estimate Summary (1.0% S in HFO)

Table 5.1.2.2, Estimate Summary (0.5% S in HFO)

Tables 5.1.2.3 (a) to (g) inclusive, Estimate Detail

All $ x 1000

TABLE 5.1.2.1

ESTIMATE SUMMARY - (1.0% S IN HFO)

QUEBEC

REFINERY NUMBER	REFINERY OWNER	REFINERY LOCATION	VAC. RESID. CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULFUR CAPITAL COST	TOTAL CAP. INVESTMENT
Q1	BP	Ville D'Anjou	28,650	13,000*	2,040*	4,150	47,840
Q2	Ultramar	Quebec	32,070	13,320*	2,070*	4,820	52,280
Q3	Gulf	Montreal	29,000	13,000*	2,040*	4,240	48,280
Q4	Imperial	Montreal	28,900	13,000*	2,040*	4,240	48,180
Q5	Petrocan	Montreal	31,040	13,000*	2,040*	4,630	50,710
Q6.	Shell	Montreal	33,010	13,000*	2,250	5,635	53,895
Q7	Texaco	Montreal	28,550	13,000*	2,040*	4,100	47,690
			211,220	91,320	14,520	31,815	348,875

* See Sect. 2.12.2, Pricing Basis

All $ x 1000

TABLE 5.1.2.2

ESTIMATE SUMMARY - (.5% S IN HFO)

QUEBEC

REFINERY NUMBER	REFINERY OWNER	REFINERY LOCATION	VAC. RESID. HDS CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULFUR CAPITAL COST	TOTAL CAP. INVESTMENT
Q1	BP	Ville D'Anjou	32,300	13,200*	4,120	5,200	54,820
Q2	Ultramar	Quebec	36,490	20,170	4,080	6,280	67,020
Q3	Gulf	Montreal	32,810	13,200*	3,400	5,710	55,120
Q4	Imperial	Montreal	32,810	13,200*	3,400	5,700	55,110
Q5	Petrocan	Montreal	35,240	14,650	4,010	6,110	60,010
Q6	Shell	Montreal	37,930	17,310	3,500	6,990	65,730
Q7	Texaco	Montreal	33,920	13,200*	3,310	5,530	55,960
			241,500	104,930	25,820	41,520	413,770

* See Sect. 2.12.2, Pricing Basis

REF. # Q1
REF. OWNER BP
REF. LOC. Ville D'Anjou

TABLE 5.1.2.3. (a)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	10,600		9,400	
2. Labour & Material	14,400		12,800	
3. Offsites, etc.	1,700		1,450	
Direct Costs		26,700		23,650
H2 PLANT				
1. New Equipment	5,090		5,090	
2. Labour & Material	4,350		4,240	
3. Offsites, etc.	1,700		1,680	
Direct Costs		11,140		11,010
AMINE				
1. New Equipment	1,650		700	
2. Labour & Material	1,300		750	
3. Offsites, etc.	530		310	
Direct Costs		3,480		1,760
SULPHUR				
1. New Equipment	2,280		1,885	
2. Labour & Material	1,740		1,325	
3. Offsites, etc.	490		390	
Direct Costs		4,510		3,600
TOTAL DIRECT COSTS		45,830		40,020
H.O. ENGINEERING COST		6,480		5,694
CATALYST COST		2,510		2,126
TOTAL CAPITAL INVESTMENT		54,820		47,840

REF. # Q2
REF. OWNER Ultramar
REF. LOC. Quebec

TABLE 5.1.2.3. (b)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	11,930		10,400	
2. Labour & Material	16,160		14,500	
3. Offsites, etc.	2,100		1,660	
Direct Costs		30,190		26,560
H2 PLANT				
1. New Equipment	7,890		5,090	
2. Labour & Material	6,720		4,480	
3. Offsites, etc.	2,560		1,720	
Direct Costs		17,170		11,290
AMINE				
1. New Equipment	1,410		700	
2. Labour & Material	1,510		780	
3. Offsites, etc.	530		270	
Direct Costs		3,450		1,750
SULPHUR				
1. New Equipment	2,810		2,190	
2. Labour & Material	2,050		1,610	
3. Offsites, etc.	590		460	
Direct Costs		5,450		4,260
TOTAL DIRECT COSTS		56,260		43,860
H.O. ENGINEERING COST		7,840		6,035
CATALYST COST		2.920		2,385
TOTAL CAPITAL INVESTMENT		67,020		52,280

REF. # 03
REF. OWNER Gulf
REF. LOC. Montreal

TABLE 5.1.2.3. (c)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	10,800		9.500	
2. Labour & Material	14,500		12,900	
3. Offsites, etc.	1,810		1,580	
Direct Costs		27,110		23,980
H2 PLANT				
1. New Equipment	5,090		5,090	
2. Labour & Material	4,350		4,240	
3. Offsites, etc.	1,700		1,680	
Direct Costs		11,140		11,010
AMINE				
1. New Equipment	1,180		700	
2. Labour & Material	1,260		750	
3. Offsites, etc.	440		310	
Direct Costs		2,880		1,760
SULPHUR				
1. New Equipment	2,590		1,930	
2. Labour & Material	1,840		1,350	
3. Offsites, etc.	530		395	
Direct Costs		4,960		3,675
TOTAL DIRECT COSTS		46,090		40,425
H.O. ENGINEERING COST		6,440		5,709
CATALYST COSTS		2,590		2,146
TOTAL CAPITAL INVESTMENT		55,120		48,280

REF. # Q4
REF. OWNER Imperial
REF. LOC. Montreal

TABLE 5.1.2.3 (d)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	10,800		9,500	
2. Labour & Material	14,500		12,800	
3. Offsites, etc.	1,810		1,580	
Direct Costs		27,110		23,880
H2 PLANT				
1. New Equipment	5,090		5,090	
2. Labour & Material	4,350		4,240	
3. Offsites, etc.	1,700		1,680	
Direct Costs		11,140		11,010
AMINE				
1. New Equipment	1,180		700	
2. Labour & Material	1,260		750	
3. Offsites, etc.	440		310	
Direct Costs		2,880		1,760
SULPHUR				
1. New Equipment	2,590		1,930	
2. Labour & Material	1,830		1,350	
3. Offsites, etc.	530		395	
Direct Costs		4,950		3,675
TOTAL DIRECT COSTS		46,480		40,325
H.O. ENGINEERING COST		6,440		5,709
CATALYST COST		2,590		2,146
TOTAL CAPITAL INVESTMENT		55,110		48,180

REF. # Q5
REF. OWNER Petrocan
REF. LOC. Montreal

TABLE 5.1.2.3 (e)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	11,700		10,200	
2. Labour & Material	15,300		13,800	
3. Offsites, etc.	2,060		1,660	
Direct Costs		29,060		25,660
H2 PLANT				
1. New Equipment	5,700		5,090	
2. Labour & Material	4,780		4,240	
3. Offsites, etc.	1,840		1,680	
Direct Costs		12,320		11,010
AMINE				
1. New Equipment	1,410		700	
2. Labour & Material	1,460		750	
3. Offsites, etc.	520		310	
Direct Costs		3,390		1,760
SULPHUR				
1. New Equipment	2,720		2,110	
2. Labour & Material	2,010		1,480	
3. Offsites, etc.	570		430	
Direct Costs		5,300		4,020
TOTAL DIRECT COSTS	50,070		42,450	
H.O. ENGINEERING COST	7,045		5,954	
CATALYST COST	2,895		2,306	
TOTAL CAPITAL INVESTMENT		60,010		50,710

REF. # Q6
REF. OWNER Shell
REF. LOC. Montreal

TABLE 5.1.2.3 (f)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	12,800		11,000	
2. Labour & Material	16,100		14,500	
3. Offsites, etc.	2,280		1,810	
Direct Costs		31,180		27,310
H2 PLANT				
1. New Equipment	6,840		5,090	
2. Labour & Material	5,610		4,246	
3. Offsites, etc.	2,120		1,680	
Direct Costs		14,570		11,010
AMINE				
1. New Equipment	1,230		780	
2. Labour & Material	1,280		830	
3. Offsites, etc.	450		340	
Direct Costs		2,960		1,950
SULPHUR				
1. New Equipment	3,160		2,370	
2. Labour & Material	2,250		1,720	
3. Offsites, etc.	650		780	
Direct Costs		6,060		4,870
TOTAL DIRECT COSTS		54,770		45,140
H.O. ENGINEERING COST		7,805		6,312
CATALYST COST		3,155		2,443
TOTAL CAPITAL INVESTMENT		65,730		53,895

REF. # Q7
REF. OWNER Texaco
REF. LOC. Montreal

TABLE 5.1.2.3 (g)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	11,000		9,400	
2. Labour & Material	14,400		12,800	
3. Offsites, etc.	1,910		1,440	
Direct Costs		27,310		23,640
H2 PLANT				
1. New Equipment	5,090		5,090	
2. Labour & Material	4,360		4,240	
3. Offsites, etc.	1,700		1,680	
Direct Costs		11,140		11,010
AMINE				
1. New Equipment	1,150		700	
2. Labour & Material	1,220		750	
3. Offsites, etc.	430		310	
Direct Costs		2,800		1,760
SULPHUR				
1. New Equipment	2,500		1,840	
2. Labour & Material	1,780		1,330	
3. Offsites, etc.	520		380	
Direct Costs		4,800		3,550
TOTAL DIRECT COSTS		46,050		39,960
H.O. ENGINEERING COST		7,450		5,640
CATALYST COST		2,460		2,126
TOTAL CAPITAL INVESTMENT		55,960		47,690

5.1.3 ONTARIO REGION

The estimated capital investment costs for Ontario are presented in the following tables.

Table 5.1.3.2, Estimate Summary (0.5 % S in HFO)

Tables 5.1.3.3. (a) to (h) inclusive, Estimate Detail

TABLE 5.1.3.2

All $ x 1000

ESTIMATE SUMMARY - (.5% S in HFO)

ONTARIO

REFINERY #	REFINERY OWNER	REFINERY LOCATION	VAC. RESID. CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULPHUR CAPITAL COST	TOTAL CAPITAL INVESTMENT
01	BP	Oakville	36,580	-	2,100	3,050	41,730
02	Gulf	Clarkson	35,740		2,100	3,050	40,890
03	Imperial	Sarnia	34,300		3,170	4,160	41,630
04	Petrosar	Sarnia	38,010		3,030	4,680	45,720
05	Shell	Oakville	26,350		2,100	3,050	31,500
06	Shell	Sarnia	29,780		2,170	3,220	35,170
07	Suncor	Sarnia	40,150		2,170	3,430	45,750
08	Texaco	Nanticoke	48,470		2,510	4,020	55,000
			289,380		19,350	28,660	337,390

REF. # 01
REF. OWNER BP
REF. LOC. Oakville

TABLE 5.1.3.3 (a)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	11,800		
2. Labour & Material	17,375		
3. Offsites, etc.	1,605		
Direct Costs		30,780	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	754		
3. Offsites, etc.	324		
Direct Costs		1,780	
SULPHUR			
1. New Equipment	1,370		
2. Labour & Material	1,000		
3. Offsites, etc.	270		
Direct Costs		2,640	
TOTAL DIRECT COSTS		35,200	
H.O. ENGINEERING COST		4,920	
CATALYST COST		1,610	
TOTAL CAPITAL INVESTMENT			41,730

REF. # 02
REF. OWNER Gulf
REF. LOC. Clarkson

TABLE 5.1.3.3 (b)

ESTIMATE DETAIL

All $ x'1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	11,475		
2. Labour & Material	17,015		
3. Offsites, etc.	1,550		
Direct Costs		30,040	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	754		
3. Offsites, etc.	324		
Direct Costs		1,780	
SULPHUR			
1. New Equipment	1,370		
2. Labour & Material	1,000		
3. Offsites, etc.	270		
Direct Costs		2,640	
TOTAL DIRECT COSTS		34,460	
H.O. ENGINEERING COST		4,820	
CATALYST COST		1,610	
TOTAL CAPITAL INVESTMENT			40,890

REF. # 03
REF. OWNER Imperial
REF. LOC. Sarnia

TABLE 5.1.3.3 (c)
ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	10,300			
2. Labour & Material	16,900			
3. Offsites, etc.	1,300			
Direct Costs		28,500		
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	1,023			
2. Labour & Material	1,247			
3. Offsites, etc.	420			
Direct Costs		2,690		
SULPHUR				
1. New Equipment	1,755			
2. Labour & Material	1,465			
3. Offsites, etc.	390			
Direct Costs		3,610		
TOTAL DIRECT COSTS		34,800		
H.O. ENGINEERING COST		4,870		
CATALYST COST		1,960		
TOTAL CAPITAL INVESTMENT		41,630		

REF. # 04
REF. OWNER Petrosar
REF. LOC. Sarnia

TABLE 5.1.3.3 (d)
ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	11,400		
2. Labour & Material	18,150		
3. Offsites, etc.	2,040		
Direct Costs		31,590	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	965		
2. Labour & Material	1,205		
3. Offsites, etc.	390		
Direct Costs		2,560	
SULPHUR			
1. New Equipment	1,975		
2. Labour & Material	1,650		
3. Offsites, etc.	435		
Direct Costs		4,060	
TOTAL DIRECT COSTS		38,210	
H.O. ENGINEERING COST		5,350	
CATALYST COST		2,160	
TOTAL CAPITAL INVESTMENT		45,720	

REF. # 05
REF. OWNER Shell
REF. LOC. Oakville

TABLE 5.1.3.3 (e)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	8,340		
2. Labour & Material	12,280		
3. Offsites, etc.	1,180		
Direct Costs		21,800	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	754		
3. Offsites, etc.	324		
Direct Costs		1,780	
SULPHUR			
1. New Equipment	1,370		
2. Labour & Material	1,000		
3. Offsites, etc.	270		
Direct Costs		2,640	
TOTAL DIRECT COSTS		26,220	
H.O. ENGINEERING COST		3,670	
CATALYST COST		1,610	
TOTAL CAPITAL INVESTMENT			31,500

REF. # 06
REF. OWNER Shell
REF. LOC. Sarnia

TABLE 5.1.3.3 (f)

ESTIMATE DETAIL

All $ x|1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	8,400		
2. Labour & Material	14,970		
3. Offsites, etc.	1,440		
Direct Costs		24,810	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	854		
3. Offsites, etc.	284		
Direct Costs		1,840	
SULPHUR			
1. New Equipment	1,380		
2. Labour & Material	1,110		
3. Offsites, etc.	300		
Direct Costs		2,790	
TOTAL DIRECT COSTS		29,440	
H.O. ENGINEERING COST		4,110	
CATALYST COSTS		1,620	
TOTAL CAPITAL INVESTMENT			35,170

REF. # 07
REF. OWNER Suncor
REF. LOC. Sarnia

TABLE 5.1.3.3 (g)

ESTIMATE DETAIL

All $ x|1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	12,240		
2. Labour & Material	19,880		
3. Offsites, etc.	1,700		
Direct Costs		33,820	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	854		
3. Offsites, etc.	284		
Direct Costs		1,840	
SULPHUR			
1. New Equipment	1,450		
2. Labour & Material	1,205		
3. Offsites, etc.	325		
Direct Costs		2,980	
TOTAL DIRECT COSTS		38,640	
H.O. ENGINEERING COST		5,395	
CATALYST COST		1,715	
TOTAL CAPITAL INVESTMENT			45,750

REF. # 08
REF. OWNER Texaco
REF. LOC. Nanticoke

TABLE 5.1.3.3 (h)

ESTIMATE DETAIL

All $ x.1000

	0.5% S in HFO		1.0% S in HFO
VAC. RESID. HDS			
1. New Equipment	12,740		
2. Labour & Material	26,500		
3. Offsites, etc.	1,880		
Direct Costs		41,120	
H2 PLANT			
1. New Equipment			
2. Labour & Material			
3. Offsites, etc.			
Direct Costs			
AMINE			
1. New Equipment	702		
2. Labour & Material	1,094		
3. Offsites, etc.	324		
Direct Costs		2,120	
SULPHUR			
1. New Equipment	1,490		
2. Labour & Material	1,625		
3. Offsites, etc.	375		
Direct Costs		3,490	
TOTAL DIRECT COSTS		46,730	
H.O. ENGINEERING COST		6,540	
CATALYST COST		1,730	
TOTAL CAPITAL INVESTMENT			55,000

5.1.4 WESTERN REGION

The capital investment cost estimations for Western region are presented in the following tables.

Table 5.1.4.1,	Estimate Summary (1.0% S in HFO)
Table 5.1.4.2,	Estimate Summary (0.5% S in HFO)
Tables 5.1.4.3 (a) to (p) inclusive,	Estimate Detail

TABLE 5.1.4.1

ESTIMATE SUMMARY - (1% in HFO)

WESTERN

All $ x 1000

REFINERY #	REFINERY OWNER	REFINERY LOCATION	VAC.RESID. CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULPHUR CAPITAL COST	TOTAL CAPITAL INVESTMENT
W-1	Chevron	Burnaby	31,820*	-	2,365*	4,160	38,345
W-2	Gulf	Kamloops	34,845*	-	2,550*	3,660*	41,055
W-3	Gulf	Port Moody	34,785*	-	2,550*	4,615	41,950
W-4	Husky	Prince George	34,840*	-	2,550*	3,660*	41,050
W-5	Imperial	Ioco	34,890*	-	2,550*	4,800	42,240
W-6	Petrocan	Taylor	34,840*	-	2,550*	3,660*	41,050
W-7	Shell	Burnaby	34,840*	-	2,550*	3,660*	41,050
W-8	Gulf	Calgary	31,800*	-	2,365*	3,520*	37,685
W-9	Gulf	Edmonton	33,835*	-	3,205	6,425	43,465
W-10	Husky	Lloydminster	33,495*	-	2,460*	3,630*	39,585
W-11	Imperial	Edmonton	46,210	-	4,400	8,750	59,360
W-12	Shell	Bowden	33,495*	-	2,460*	3,630*	39,585
W-13	Texaco	Edmonton	33,495*	-	2,460*	3,630	39,585
W-14	Consumers	Regina	30,820*	-	2,320*	4,410	37,550
W-15	Gulf	Moose Jaw	31,000*	-	2,320*	4,410	37,730
W-16	Shell	St. Boniface	30,960*	-	2,320*	3,800	37,080
			545,970		41,975	70,420	658,365

* See Sect. 2.12.2, Pricing Basis

TABLE 5.1.4.2

ESTIMATE SUMMARY - (.5% in HFO)

WESTERN

All $ x 1000

REFINERY #	REFINERY OWNER	REFINERY LOCATION	VAC. RESID. CAPITAL COST	AMINE CAPITAL COST	SULPHUR CAPITAL COST	TOTAL CAPITAL INVESTMENT
W-1	Chevron	Burnaby	31,920*	2,375*	4,520	38,815
W-2	Gulf	Kamloops	34,850*	2,560*	3,765*	41,175
W-3	Gulf	Port Moody	34,950*	2,560*	5,050	42,560
W-4	Husky	Prince George	34,865*	2,560*	3,765*	41,190
W-5	Imperial	Ioco	34,940*	2,560*	5,210	42,710
W-6	Petrocan	Taylor	34,845*	2,560*	3,765*	41,170
W-7	Shell	Burnaby	34,840*	2,560*	3,765*	41,165
W-8	Gulf	Calgary	31,810*	2,380*	3,765*	37,955
W-9	Gulf	Edmonton	34,030*	4,010*	6,960	45,000
W-10	Husky	Lloydminster	33,500*	2,470*	3,630*	39,600
W-11	Imperial	Edmonton	50,580	5,150	9,450	65,180
W-12	Shell	Bowden	33,500*	2,470*	3,630*	39,600
W-13	Texaco	Edmonton	33,510*	2,470	3,825	39,805
W-14	Consumers	Regina	30,900*	2,330*	4,795	38,025
W-15	Gulf	Moose Jaw	31,080*	2,330*	4,795	38,205
W-16	Shell	St. Boniface	31,000*	2,330*	4,100	37,430
			551,120	43,675	74,790	669,585

** See Sect. 2.12.2, Pricing Basis

All $ x 1000

TABLE 5.1.4.3 (a)

ESTIMATE DETAIL

REF. # W-1
REF. OWNER Chevron
REF. LOC. Burnaby

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	16,690		16,690	
3. Offsites, etc.	1,370		1,285	
Direct Costs		26,685		26,600
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	974		976	
3. Offsites, etc.	310		307	
Direct Costs		2,010		2,000
SULPHUR				
1. New Equipment	1,815		1,669	
2. Labour & Material	1,659		1,553	
3. Offsites, etc.	446		388	
Direct Costs		3,920		3,610
TOTAL DIRECT COSTS		32,615		32,210
H.O. ENGINEERING COST		4,565		4,500
CATALYST COST		1,635		1,635
TOTAL CAPITAL INVESTMENT		38,815		38,345

REF. # W-2
REF. OWNER Gulf
REF. LOC. Kamloops

TABLE 5.1.4.3 (b)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,135		1,130	
Direct Costs		29,250		29,245
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,490		1,490	
3. Offsites, etc.	354		354	
Direct Costs		3,260		3,260
TOTAL DIRECT COSTS		34,680		34,665
H.O. ENGINEERING COST		4,860		4,755
CATALYST COST		1,635		1,635
TOTAL CAPITAL INVESTMENT		41,175		41,055

REF. # W-3.
REF. OWNER Gulf
REF. LOC. Port Moody

TABLE 5.1.4.3 (c)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,225		1,170	
Direct Costs		29,340		29,285
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,905		1,724	
2. Labour & Material	2,000		1,842	
3. Offsites, etc.	475		434	
Direct Costs		4,380		4,000
TOTAL DIRECT COSTS		35,890		35,445
H.O. ENGINEERING COST		5,020		4,960
CATALYST COST		1,650		1,545
TOTAL CAPITAL INVESTMENT		42,560		41,950

REF. # W-4
REF. OWNER Husky
REF. LOC. Prince George

TABLE 5.1.4.3 (d)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,150		1,125	
Direct Costs		29,265		29,240
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,490		1,490	
3. Offsites, etc.	354		354	
Direct Costs		3,260		3,260
TOTAL DIRECT COSTS		34,695		34,660
H.O. ENGINEERING COST		4,860		4,755
CATALYST COST		1,635		1,635
TOTAL CAPITAL INVESTMENT		41,190		41,050

REF. # W-5
REF. OWNER Imperial
REF. LOC. Ioco

TABLE 5.1.4.3 (e)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,215		1,175	
Direct Costs		29,330		29,290
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,951		1,815	
2. Labour & Material	2,082		1,899	
3. Offsites, etc.	487		446	
Direct Costs		4,520		4,160
TOTAL DIRECT COSTS		36,020		35,610
H.O. ENGINEERING COST		5,040		4,980
CATALYST COST		1,650		1,650
TOTAL CAPITAL INVESTMENT		42,710		42,240

REF. # W-6
REF. OWNER Petrocan
REF. LOC. Taylor

TABLE 5.1.4.3 (f)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,130		1,125	
Direct Costs		29,245		29,240
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,490		1,490	
3. Offsites, etc.	354		354	
Direct Costs		3,260		3,260
TOTAL DIRECT COSTS		34,675		34,660
H.O. ENGINEERING COST		4,860		4,755
CATALYST COST		1,635		1,635
TOTAL CAPITAL INVESTMENT		41,170		41,050

REF. # W-7
REF. OWNER Shell
REF. LOC. Burnaby

TABLE 5.1.4.3 (g)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	19,490		19,490	
3. Offsites, etc.	1,130		1,125	
Direct Costs		29,240		29,240
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,110		1,112	
3. Offsites, etc.	334		331	
Direct Costs		2,170		2,160
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,490		1,490	
3. Offsites, etc.	354		354	
Direct Costs		3,260		3,260
TOTAL DIRECT COSTS		34,670		34,660
H.O. ENGINEERING COST		4,860		4,755
CATALYST COSTS		1,635		1,635
TOTAL CAPITAL INVESTMENT		41,165		41,050

REF. # W-8
REF. OWNER Gulf
REF. LOC. Calgary

TABLE 5.1.4.3 (h)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	16,690		16,690	
3. Offsites, etc.	1,275		1,265	
Direct Costs		26,590		26,580
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	974		976	
3. Offsites, etc.	310		307	
Direct Costs		2,010		2,000
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,490		1,302	
3. Offsites, etc.	354		332	
Direct Costs		3,260		3,050
TOTAL DIRECT COSTS		31,860		31,630
H.O. ENGINEERING COST		4,460		4,430
CATALYST COST		1,635		1,625
TOTAL CAPITAL INVESTMENT		37,955		37,685

REF. # W-9
REF. OWNER Gulf
REF. LOC. Edmonton

TABLE 5.1.4.3 (1)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	8,625		8,625	
2. Labour & Material	18,090		18,090	
3. Offsites, etc.	1,815		1,650	
Direct Costs		28,530		28,365
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	1,207		967	
2. Labour & Material	1,673		1,325	
3. Offsites, etc.	520		418	
Direct Costs		3,400		2,710
SULPHUR				
1. New Equipment	2,686		2,468	
2. Labour & Material	2,705		2,498	
3. Offsites, etc.	649		604	
Direct Costs		6,040		5,570
TOTAL DIRECT COSTS		37,970		36,645
H.O. ENGINEERING COST		5,310		5,130
CATALYST COST		1,720		1,690
TOTAL CAPITAL INVESTMENT		45,000		43,465

REF. # W-10
REF. OWNER Husky
REF. LOC. Lloydminster

TABLE 5.1.4.3 (1)

ESTIMATE DETAIL

All $ x 1000

VAC. RESID. HDS	0.5% S in HFO		1.0% S in HFO	
1. New Equipment	8,625		8,625	
2. Labour & Material	18,090		18,090	
3. Offsites, etc.	1,355		1,350	
Direct Costs		28,070		28,065
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,042		1,044	
3. Offsites, etc.	322		319	
Direct Costs		2,090		2,080
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,396		1,396	
3. Offsites, etc.	338		338	
Direct Costs		3,150		3,150
TOTAL DIRECT COSTS		33,310		33,295
H.O. ENGINEERING COST		4,660		4,660
CATALYST COST		1,630		1,630
TOTAL CAPITAL INVESTMENT		39,600		39,585

REF. # W-11
REF. OWNER Imperial
REF. LOC. Edmonton

TABLE 5.1.4.3 (k)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	14,245		12,798	
2. Labour & Material	26,085		24,132	
3. Offsites, etc.	2,460		2,200	
Direct Costs		42,790		39,130
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	1,540		1,270	
2. Labour & Material	2,156		1,876	
3. Offsites, etc.	664		574	
Direct Costs		4,360		3,720
SULPHUR				
1. New Equipment	3,629		3,357	
2. Labour & Material	3,677		3,417	
3. Offsites, etc.	884		816	
Direct Costs		8,190		7,590
TOTAL DIRECT COSTS		55,340		50,440
H.O. ENGINEERING COST		7,750		7,060
CATALYST COST		2,090		1,860
TOTAL CAPITAL INVESTMENT		65,180		59,360

REF. # W-12
REF. OWNER Shell
REF. LOC. Bowden

TABLE 5.1.4.3 (1)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	18,090		18,090	
3. Offsites, etc.	1,355		1,350	
Direct Costs		28,070		28,065
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,042		1,044	
3. Offsites, etc.	322		319	
Direct Costs		2,090		2,080
SULPHUR				
1. New Equipment	1,416		1,416	
2. Labour & Material	1,396		1,396	
3. Offsites, etc.	338		338	
Direct Costs		3,150		3,150
TOTAL DIRECT COSTS		33,310		33,295
H.O. ENGINEERING COST		4,660		4,660
CATALYST COST		1,630		1,630
TOTAL CAPITAL INVESTMENT		39,600		39,585

REF. # W-13
REF. OWNER Texaco
REF. LOC. Edmonton

TABLE 5.1.4.3 (m)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	18,090		18,090	
3. Offsites, etc.	1,365		1,350	
Direct Costs		28,080		28,065
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	1,042		1,044	
3. Offsites, etc.	322		319	
Direct Costs		2,090		2,080
SULPHUR				
1. New Equipment	1,488		1,416	
2. Labour & Material	1,474		1,396	
3. Offsites, etc.	358		338	
Direct Costs		3,320		3,150
TOTAL DIRECT COSTS		33,490		33,295
H.O. ENGINEERING COST		4,680		4,660
CATALYST COST		1,635		1,630
TOTAL CAPITAL INVESTMENT		39,805		39,585

REF. # W-14
REF. OWNER Consumers
REF. LOC. Regina

TABLE 5.1.4.3 (n)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	15,990		15,990	
3. Offsites, etc.	1,345		1,265	
Direct Costs		25,960		25,880
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	940		942	
3. Offsites, etc.	304		301	
Direct Costs		1,970		1,960
SULPHUR				
1. New Equipment	1,951		1,815	
2. Labour & Material	1,757		1,599	
3. Offsites, etc.	452		416	
Direct Costs		4,160		3,830
TOTAL DIRECT COSTS		32,090		31,670
H.O. ENGINEERING COST		4,295		4,245
CATALYST COST		1,640		1,635
TOTAL CAPITAL INVESTMENT		38,025		37,550

REF. # W-15
REF. OWNER Gulf
REF. LOC. Moose Jaw

TABLE 5.1.4.3 (o)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	15,990		15,990	
3. Offsites, etc.	1,335		1,265	
Direct Costs		25,950		25,880
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	940		942	
3. Offsites, etc.	304		301	
Direct Costs		1,970		1,960
SULPHUR				
1. New Equipment	1,951		1,815	
2. Labour & Material	1,757		1,599	
3. Offsites, etc.	452		416	
Direct Costs		4,160		3,830
TOTAL DIRECT COSTS		32,080		31,670
H.O. ENGINEERING COST		4,485		4,425
CATALYST COST		1,640		1,635
TOTAL CAPITAL INVESTMENT		38,205		37,730

REF. # W-16
REF. OWNER Shell
REF. LOC. St. Boniface

TABLE 5.1.4.3 (p)

ESTIMATE DETAIL

All $ x 1000

	0.5% S in HFO		1.0% S in HFO	
VAC. RESID. HDS				
1. New Equipment	8,625		8,625	
2. Labour & Material	15,990		15,990	
3. Offsites, etc.	1,265		1,225	
Direct Costs		25,880		25,840
H2 PLANT				
1. New Equipment				
2. Labour & Material				
3. Offsites, etc.				
Direct Costs				
AMINE				
1. New Equipment	726		717	
2. Labour & Material	940		942	
3. Offsites, etc.	304		301	
Direct Costs		1,970		1,960
SULPHUR				
1. New Equipment	1,669		1,540	
2. Labour & Material	1,497		1,401	
3. Offsites, etc.	384		359	
Direct Costs		3,550		3,300
TOTAL DIRECT COSTS		31,400		31,100
H.O. ENGINEERING COST		4,395		4,355
CATALYST COST		1,635		1,625
TOTAL CAPITAL INVESTMENT		37,430		37,080

5.2 INCREASED ANNUAL COST OF OPERATING MATERIALS

5.2.1 ATLANTIC REGION

The negligible amount of chemicals cost was not taken into consideration in Case 1. The total costs involved for Case 1 is minimal if compared with those of other 2 Cases.

The largest single cost of operating materials for each case is that of energy. This cost is dominating and should be considered of importance.

The second largest cost is that of catalyst.

The increased cost due to the changes of fuel specification is presented in Table 5.2.1.

The increased annual cost of energy, for each specification, calculated from the quantities of crude oil equivalent and at '79 Atlantic crude and other specified prices are shown in Table 5.2.1 (a).

5.2.2 QUEBEC REGION

Similar to the results of Atlantic, energy cost in each case in Quebec is decisive though it is much less than that in Atlantic, as shown in Table 5.2.2.

The increased annual cost of energy, for each specification, calculated from the quantities of crude oil equivalent and at '79 Quebec crude and other specified prices are included in Table 5.2.2. (a).

TABLE 5.2.1

INCREASED ANNUAL COST OF OPERATING MATERIALS ATLANTIC REGION

Case	Specification (Increased Cost (Annual*))	Operating Materials				
		Energy MM$	Cooling Water MM$	Catalyst MM$	Chemicals MM$	Total MM$
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	1.03	0.02	0.01	-	1.06
2 (i)	HFO (#4, #5 & #6) 1.0 wt.% S, max.	93.22	1.39	5.86	0.05	100.52
2 (ii)	HFO (#4, #5 & #6) 0.5 wt.%S, max.	123.67	1.76	13.85	0.06	139.34
1 + 2 (i) o	Combination of 1 and 2 (i)	93.22	1.39	5.86	0.05	100.52
1 + 2 (ii) •	Combination of 1 and 2 (ii)	123.67	1.76	13.85	0.06	139.34

o Same as 2 (i)

• Same as 2 (ii)

* Annual = 325 days per year

TABLE 5.2.1 (a)

INCREASED ANNUAL COST OF CRUDE OIL (EQUIVALENT TO ENERGY REQUIREMENTS) ATLANTIC REGION

Case	Increased Annual* / Specification	COST OF CRUDE OIL (ENERGY EQUIVALENT) MM $				
		79 Price $23.18/Bbl	$20/Bbl	$25/Bbl	$30/Bbl	$35/Bbl
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	1.36	1.17	1.47	1.76	2.05
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	92.95	80.19	100.24	120.29	140.34
2 (ii)	HFO (#4,#5, #6) 0.5 wt. % S, max.	124.05	107.03	133.79	160.55	187.31
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	92.95	80.19	100.24	120.29	140.34
1 + 2 (ii)	Combination of Case 1 and Case 2(ii)	124.05	107.03	133.79	160.55	187.31

* Annual = 325 Days per Year

TABLE 5.2.2

INCREASED ANNUAL COST OF OPERATING MATERIALS QUEBEC REGION

Case	Increased Cost (Annual*) / Specification	Operating Materials				
		Energy MM$	Cooling Water MM$	Catalyst MM$	Chemicals MM$	Total MM$
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	4.55	0.15	0.19	-	4.89
2 (i)	HFO (#4, #5 & #6) 1.0 wt.% S, max.	26.27	0.75	2.49	0.02	29.53
2 (ii)	HFO (#4, #5 & #6) 0.5 wt.% S, max.	54.35	1.11	4.25	0.03	59.74
1 + 2 (i)	Combination of 1 and 2 (i)	26.27	0.75	2.49	0.02	29.53
1 + 2 (ii)	Combination of 1 and 2 (ii)	54.35	1.11	4.25	0.03	59.74

o Same as 2 (i)
• Same as 2 (ii)

*Annual = 325 days per year

TABLE 5.2.2. (a)

INCREASED ANNUAL COST OF CRUDE OIL (EQUIVALENT TO ENERGY REQUIREMENTS) QUEBEC REGION

Case	Increased Annual* Specification	COST OF CRUDE OIL (ENERGY EQUIVALENT) MM $				
		79 Price $18.88/Bbl	$20/Bbl	$25/Bbl	$30/Bbl	$35/Bbl
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	5.62	5.96	7.45	8.94	10.42
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	27.52	29.15	36.44	43.73	51.02
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	52.74	55.87	69.83	83.80	97.77
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	27.52	29.15	36.44	43.73	51.02
1 + 2 (ii)	Combination of Case 1 and Case 2(ii)	52.74	55.87	69.83	83.80	97.77

* Annual = 325 Days per Year

5.2.3 ONTARIO REGION

The total increased cost of operating materials for the worst case, e.g. Case 2 (ii), $7.38 MM per annum, Table 5.2.3, is only marginal compared with those of Atlantic and Quebec, $139,74 per annum and $59.74 per annum respectively.

The increased annual cost of energy calculated from its equivalent of crude oil quantities and at '79 Ontario crude and other specified prices are shown in Table 5.2.3 (a).

5.2.4 WESTERN REGION

Table 5.2.4 shows the negligible increased cost of operating materials, $2.71 MM/annum.

The higher energy cost in Case 1 was due to the assumption that no steam would be credited to the increased energy cost unless it was generated from the new sulfur recovery plant (no new sulfur plant requirement in Case 1).

The increased annual cost of energy calculated from its crude oil equivalent and at '79 Western crude and other specified prices are presented in Table 5.2.4 (a).

TABLE 5.2.3

INCREASED ANNUAL COST OF OPERATING MATERIALS ONTARIO REGION

Case	Increased Cost (Annual*) / Specification	Operating Materials				
		Energy MM$	Cooling Water MM$	Catalyst MM$	Chemicals MM$	Total MM$
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	0.11	0.01	0.02	-	0.14
2 (i)	HFO (#4, #5 & #6) 1.0 wt.% S, max.	0.11	0.01	0.02	-	0.14
2 (ii)	HFO (#4, #5 & #6) 0.5 wt.% S, max.	3.82	0.05	3.49	0.02	7.38
o 1 + 2 (i)	Combination of 1 and 2 (i)	0.11	0.01	0.02	-	0.14
• 1 + 2 (ii)	Combination of 1 and 2 (ii)	3.82	0.05	3.49	0.02	7.38

o Same as 2 (i)

• Same as 2 (ii)

* Annual = 325 days per year

TABLE 5.2.3 (a)

INCREASED ANNUAL COST OF CRUDE OIL (EQUIVALENT TO ENERGY REQUIREMENTS) ONTARIO REGION

Case	Specification / Increased Annual*	COST OF CRUDE OIL (ENERGY EQUIVALENT) MM $				
		79 Price $14.73/Bbl	$20/Bbl	$25/Bbl	$30/Bbl	$35/Bbl
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	0.11	0.15	0.19	0.23	0.26
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	0.11	0.15	0.19	0.23	0.26
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	4.92	6.69	8.36	10.03	11.70
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	0.11	0.15	0.19	0.23	0.26
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	4.92	6.69	8.36	10.03	11.70

* Annual = 325 Days per Year

TABLE 5.2.4

INCREASED ANNUAL COST OF OPERATING MATERIALS WESTERN REGION

Case	Increased Cost (Annual*) / Specification	Operating Materials				
		Energy MM$	Cooling Water MM$	Catalyst MM$	Chemicals MM$	Total MM$
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	0.54	0.03	0.04	-	0.61
2 (i)	HFO (#4, #5 & #6) 1.0 wt.% S, max.	0.37	0.07	1.29	0.03	1.76
2 (ii)	HFO (#4, #5 & #6) 0.5 wt.% S, max	0.53	0.08	2.06	0.03	2.70
1 + 2 (i)	Combination of 1 and 2 (i)	0.54	0.07	1.29	0.03	1.93
1 + 2 (ii)	Combination of 1 and 2 (ii)	0.54	0.08	2.06	0.03	2.71

* Annual = 325 days per year

TABLE 5.2.4 (a)

INCREASED ANNUAL COST OF CRUDE OIL (EQUIVALENT TO ENERGY REQUIREMENTS) WESTERN REGION

Case	Increased Annual* / Specification	COST OF CRUDE OIL (ENERGY EQUIVALENT) MM $				
		79 Price $13.75/Bbl	$20/Bbl	$25/Bbl	$30/Bbl	$35/Bbl
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max.	0.75	1.10	1.37	1.64	1.92
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	1.33	1.94	2.42	2.91	3.39
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	1.73	2.52	3.15	3.78	4.41
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	1.33	1.94	2.42	2.91	3.39
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	1.73	2.52	3.15	3.78	4.41

* Annual = 325 Days per Year

5.3 COST SUMMARY

The cost summary "A" for Atlantic, Quebec, Ontario and Western are presented in Tables 5.3.1, 5.3.2, 5.3.3 and 5.3.4 respectively.

The cost summary "B" for Atlantic, Quebec, Ontario and Western are presented in Tables 5.4.1, 5.4.2, 5.4.3 and 5.4.4 respectively.

The differences of cost summary "A" and "B" are

- In "B", Item II.3.a.the cost of increased crude includes that of crude feed and that equivalent to energy. In "A", Item II.3.a, the cost of additional crude refers to feed only.

- In "B", Item III.3.b, cost of cooling water only.
  In "A", Item III.3.b, cost of energy + cooling water.

- In III and IV, the increased annual operating cost and the increased cost per barrel of new crude feed are accordingly changed.

The difference in crude consumption between Base Case and New Crude Case increases from 0.3 % S LFO, 1.0 % S HFO to 0.5 % S HFO specifications. This is due to the need for treatment of larger portion of the heavy cyclic oil (HCO) and resids in order to attain the goal specifications. (The larger the HDS capacity the higher the losses and more crude would be required to achieve the product slates).

No capital investment was needed to achieve 0.3 % S in LFO spec. However, capital investments were required for other 2 Cases. The higher capital investments in case of 0.5 % S HFO spec. is because of larger HDS and supporting units required.

No additional fixed operating costs are shown for 0.3 % S LFO spec. because of no new installation and the assumption that no additional manpower and overheads would be involved.

The cost of additional crude increases in the following pattern:
Spec. 1, 0.3 % S LFO < Spec. 2 (i), 1.0 % S HFO < Spec. 2 (ii), 0.5 % S HFO

The sulfur, if produced as a result of desulfurization, is credited to the operating costs. More credits are allocated to spec. 2 (ii) Case, because of its severity of desulfurization, than spec. 2 (i) Case.

Neither fuel gas nor naphtha produced due to resid desulfurization, though significant, was credited. They were assumed to be consumed within the refinery.

The increased operating cost increases in the following pattern:
i.e. Spec. 1 < Spec. 2 (i) < Spec. 2 (ii).

TABLE 5.3.1

COST SUMMARY "A" ATLANTIC REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	313,229	313,229	313,229
2. New Crude Case	314,278	314,716	317,352
I Capital Investment; MM.$	N/A	610.535	710.115
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	152.63	177.53
2. Fixed Costs; MM.$/Year			
a. Operating & Supervisory Personnel	N/A	4.97	4.97
b. Maintenance	N/A	4.58	5.33
c. General, Sales, Admin, Taxes, Insurance	N/A	5.34	6.21
3. Variable Costs:			
a. Cost of Additional Crude Feed			
(i) 1979 Price ($23.18/bbl)	7.90	11.20	31.06
(ii) $20 /bbl	6.82	9.67	26.80
(iii) $25 /bbl	8.52	12.08	33.50
(iv) $30 /bbl	10.23	14.50	40.20
(v) $35 /bbl	11.93	16.91	46.90
b. Energy Requirements	1.05	94.61	125.43
4. Catalysts & Chemicals	0.01	5.91	13.95
5. Credit for Sulphur	N/A	(4.54)	(5.43)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	8.96	274.70	359.05
2. Case 3a (ii)	7.88	273.17	354.79
3. Case 3a (iii)	9.58	275.58	361.49
4. Case 3a (iv)	11.29	278.00	368.19
5. Case 3a (v)	12.99	280.41	374.89
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.088	2.686	3.481
2. Case 3a (ii)	0.077	2.671	3.440
3. Case 3a (iii)	0.094	2.694	3.505
4. Case 3a (iv)	0.111	2.718	3.570
5. Case 3a (v)	0.127	2.742	3.635

* Annum = 325 Days.

TABLE 5.3.2

COST SUMMARY "A" QUEBEC REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	510,472	510,472	510,472
2. New Crude Case	511,185	512,705	514,303
I Capital Investment; MM.$	N/A	348.875	413.770
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	87.22	103.44
2. Fixed Costs; MM.$/Year			
a. Operating & Supervisory Personnel	N/A	5.57	5.57
b. Maintenance	N/A	2.62	3.10
c. General, Sales, Admin, Taxes, Insurance	N/A	3.05	3.62
3. Variable Costs:			
a. Cost of Additional Crude Feed			
(i) 1979 Price ($18.88/bbl)	4.37	13.70	23.51
(ii) $20 /bbl	4.63	14.51	24.90
(iii) $25 /bbl	5.79	18.14	31.13
(iv) $30 /bbl	6.95	21.77	37.35
(v) $35 /bbl	8.11	25.40	43.58
b. Energy Requirements	4.70	27.02	55.46
4. Catalysts & Chemicals	0.19	2.51	4.28
5. Credit for Sulphur	N/A	(1.38)	(2.51)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	9.26	140.31	196.47
2. Case 3a (ii)	9.52	141.12	197.86
3. Case 3a (iii)	10.68	144.75	204.09
4. Case 3a (iv)	11.84	148.38	210.31
5. Case 3a (v)	13.00	152.01	216.54
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.056	0.842	1.175
2. Case 3a (ii)	0.057	0.847	1.184
3. Case 3a (iii)	0.064	0.869	1.221
4. Case 3a (iv)	0.071	0.890	1.258
5. Case 3a (v)	0.078	0.912	1.295

* Annum = 325 Days.

TABLE 5.3.3

COST SUMMARY "A" ONTARIO REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	605,147	605,147	605,147
2. New Crude Case	605,223	605,223	608,570
I Capital Investment; MM.$	N/A	N/A	337.39
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	N/A	84.35
2. Fixed Costs; MM$/Year			
a. Operating & Supervisory Personnel	N/A	N/A	4.78
b. Maintenance	N/A	N/A	2.53
c. General, Sales, Admin, Taxes, Insurance	N/A	N/A	2.95
3. Variable Costs:			
a. Cost of Additional Crude Feed			
(i) 1979 Price ($14.73/bbl)	0.36	0.36	16.39
(ii) $20 /bbl	0.49	0.49	22.25
(iii) $25 /bbl	0.62	0.62	27.81
(iv) $30 /bbl	0.74	0.74	33.37
(v) $35 /bbl	0.86	0.86	38.94
b. Energy Requirements	0.12	0.12	3.87
4. Catalysts & Chemicals	0.02	0.02	3.51
5. Credit for Sulphur	N/A	N/A	(0.82)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	0.50	0.50	117.56
2. Case 3a (ii)	0.63	0.63	123.42
3. Case 3a (iii)	0.76	0.76	128.98
4. Case 3a (iv)	0.88	0.88	134.54
5. Case 3a (v)	1.00	0.98	140.11
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.003	0.003	0.594
2. Case 3a (ii)	0.003	0.003	0.624
3. Case 3a (iii)	0.004	0.004	0.652
4. Case 3a (iv)	0.004	0.004	0.680
5. Case 3a (v)	0.005	0.005	0.708

* Annum = 325 Days.

TABLE 5.3.4

COST SUMMARY "A" WESTERN REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	525,420	525,420	525,420
2. New Crude Case	525,642	526,570	527,506
I Capital Investment; MM.$	N/A	658.365	669.585
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	164.59	167.39
2. Fixed Costs; MM $/Year			
a. Operating & Supervisory Personnel	N/A	4.18	4.18
b. Maintenance	N/A	4.94	5.02
c. General, Sales, Admin, Taxes, Insurance	N/A	5.76	5.86
3. Variable Costs:			
a. Cost of Additional Crude Feed			
(i) 1979 Price ($13.75/bbl)	0.99	5.14	9.32
(ii) $20 /bbl	1.44	7.48	13.56
(iii) $25 /bbl	1.80	9.34	16.95
(iv) $30 /bbl	2.16	11.21	20.34
(v) $35 /bbl	2.53	13.08	23.73
b. Energy Requirements	0.57	0.44	0.61
4. Catalysts & Chemicals	0.04	1.32	2.09
5. Credit for Sulphur	N/A	(2.01)	(2.33)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	1.60	184.36	192.14
2. Case 3a (ii)	2.05	186.70	196.38
3. Case 3a (iii)	2.41	188.56	199.77
4. Case 3a (iv)	2.77	190.43	203.16
5. Case 3a (v)	3.14	192.30	206.55
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.009	1.078	1.121
2. Case 3a (ii)	0.012	1.092	1.146
3. Case 3a (iii)	0.014	1.103	1.165
4. Case 3a (iv)	0.016	1.114	1.185
5. Case 3a (v)	0.018	1.125	1.205

* Annum = 325 Days.

TABLE 5.4.1

COST SUMMARY "B" ATLANTIC REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	313,229	313,229	313,229
2. New Crude Case	314,278	314,716	317,352
I Capital Investment; MM.$	N/A	610.535	710.115
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	152.63	177.53
2. Fixed Costs; MM$/Year			
a. Operating & Supervisory Personnel	N/A	4.97	4.97
b. Maintenance	N/A	4.58	5.33
c. General, Sales, Admin, Taxes, Insurance	N/A	5.34	6.21
3. Variable Costs:			
a. Cost of Increased Crude(Feed + Equi. to Energy)			
(i) 1979 Price ($23.18/bbl)	9.26	104.15	155.11
(ii) 20 $/bbl	7.99	89.86	133.83
(iii) 25 $/bbl	9.99	112.32	167.29
(iv) 30 $/bbl	11.99	134.79	200.75
(v) 35 $/bbl	13.98	157.25	234.21
b. Cooling Water	0.02	1.39	1.76
4. Catalysts & Chemicals	0.01	5.91	13.95
5. Credit for Sulphur	N/A	(4.54)	(5.43)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	9.29	274.43	359.43
2. Case 3a (ii)	8.02	260.14	338.15
3. Case 3a (iii)	10.02	282.60	371.61
4. Case 3a (iv)	12.02	305.07	405.07
5. Case 3a (v)	14.01	327.53	438.53
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.091	2.683	3.485
2. Case 3a (ii)	0.079	2.543	3.279
3. Case 3a (iii)	0.098	2.763	3.603
4. Case 3a (iv)	0.118	2.983	3.927
5. Case 3a (v)	0.137	3.202	4.252

* Annum = 325 Days.

TABLE 5.4.2

COST SUMMARY "B" QUEBEC REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	510,472	510,472	510,472
2. New Crude Case	511,185	512,705	514,303
I Capital Investment; MM.$	N/A	348.875	413.770
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	87.22	103.44
2. Fixed Costs; MM $/Year.			
a. Operating & Supervisory Personnel	N/A	5.57	5.57
b. Maintenance	N/A	2.62	3.10
c, General, Sales, Admin, Taxes, Insurance	N/A	3.06	3.62
3. Variable Costs:			
a, Cost of Increased Crude(Feed + Equi. to Energy)			
(i) 1979 Price ($18.88/bbl)	9.99	41.22	76.25
(ii) 20 $/bbl	10.59	43.66	80.77
(iii) 25 $/bbl	13.24	54.58	100.96
(iv) 30 $/bbl	15.89	65.50	121.15
(v) 35 $/bbl	18.53	76.42	141.35
b, Cooling Water	0.15	0.75	1.11
4. Catalysts & Chemicals	0.19	2.51	4.28
5. Credit for Sulphur	N/A	(1.38)	(2.51)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	10.33	141.56	194.86
2. Case 3a (ii)	10.93	144.00	199.38
3. Case 3a (iii)	13.58	154.92	219.57
4. Case 3a (iv)	16.23	165.84	239.76
5. Case 3a (v)	18.87	176.76	259.96
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.062	0.850	1.166
2. Case 3a (ii)	0.066	0.864	1.193
3. Case 3a (iii)	0.082	0.930	1.315
4. Case 3a (iv)	0.098	0.995	1.434
5. Case 3a (v)	0.114	1.061	1.555

* Annum = 325 Days.

TABLE 5.4.3

COST SUMMARY "B" ONTARIO REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	605,147	605,147	605,147
2. New Crude Case	605,223	605,223	608,570
I Capital Investment; MM.$	N/A	N/A	337.39
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	N/A	84.35
2. Fixed Costs; MM $/Year			
a. Operating & Supervisory Personnel	N/A	N/A	4.78
b. Maintenance	N/A	N/A	2.53
c. General, Sales, Admin, Taxes, Insurance	N/A	N/A	2.95
3. Variable Costs:			
a. Cost of Increased Crude(Feed + Equi. to Energy)			
(i) 1979 Price ($14.73/bbl)	0.47	0.47	21.31
(ii) 20 $/bbl	0.64	0.64	28.94
(iii) 25 $/bbl	0.81	0.81	36.17
(iv) 30 $/bbl	0.97	0.97	43.40
(v) 35 $/bbl	1.12	1.12	50.64
b. Cooling Water	0.01	0.01	0.05
4. Catalysts & Chemicals	0.02	0.02	3.51
5. Credit for Sulphur	N/A	N/A	(0.82)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	0.50	0.50	118.66
2. Case 3a (ii)	0.67	0.67	126.29
3. Case 3a (iii)	0.84	0.84	133.52
4. Case 3a (iv)	1.00	1.00	140.75
5. Case 3a (v)	1.15	1.15	147.99
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.003	0.003	0.600
2. Case 3a (ii)	0.003	0.003	0.639
3. Case 3a (iii)	0.004	0.004	0.675
4. Case 3a (iv)	0.005	0.005	0.712
5. Case 3a (v)	0.006	0.006	0.748

* annum = 325 Days.

TABLE 5.4.4

COST SUMMARY "B" WESTERN REGION

	0.3%S LFO	1.0%S HFO	0.5%S HFO
Capacity, BPCD			
1. Base Case	525,420	525,420	525,420
2. New Crude Case	525,642	526,570	527,506
I Capital Investment; MM.$	N/A	658.365	669.585
II Capital and Operating Costs; MM.$/Annum*			
1. Annual Capital Charges	N/A	164.59	167.39
2. Fixed Costs; MM $/Year			
a. Operating & Supervisory Personnel	N/A	4.18	4.18
b. Maintenance	N/A	4.94	5.02
c. General, Sales, Admin, Taxes, Insurance	N/A	5.76	5.86
3. Variable Costs:			
a. Cost of Increased Crude(Feed + Equi. to Energy)			
(i) 1979 Price ($13.75/bbl)	1.74	6.47	11.05
(ii) 20 $/bbl	2.54	9.42	16.08
(iii) 25 $/bbl	3.17	11.76	20.10
(iv) 30 $/bbl	3.80	14.12	24.12
(v) 35 $/bbl	4.45	16.47	28.14
b. Cooling Water	0.03	0.07	0.08
4. Catalysts & Chemicals	0.04	1.32	2.09
5. Credit for Sulphur	N/A	(2.01)	(2.33)
III Increased Annual Operating Cost; MM.$			
1. Case 3a (i)	1.81	185.32	193.34
2. Case 3a (ii)	2.61	188.27	198.37
3. Case 3a (iii)	3.24	190.61	202.39
4. Case 3a (iv)	3.87	192.97	206.41
5. Case 3a (v)	4.52	195.32	210.43
IV Increased Cost per BBL of Crude (New Crude Case); $/bbl			
1. Case 3a (i)	0.011	1.083	1.128
2. Case 3a (ii)	0.015	1.100	1.157
3. Case 3a (iii)	0.019	1.114	1.181
4. Case 3a (iv)	0.023	1.128	1.204
5. Case 3a (v)	0.026	1.141	1.227

* Annum = 325 Days.

6. SUMMARY FOR CANADA

6.1 Summary of Annual Reduction of Sulfur Due to Changes in Fuel Specification

Table 6.1 Specification 1 :
#2 Fuel Oil and Lighter, 0.3 wt. % S, max.

- Total reduction of sulfur = 36,696 t/annum

  consists of (a) Refinery own fuel consumption = 2,693 t/annum

  (b) Saleable heavy fuel oil = 11,639 t/annum

  (c) Light fuel oils = 22,354 t/annum

- Regional sulfur reduction:

  Quebec > Ontario > Western > Atlantic

- Possible increase of sulfur in Atlantic region; in particular in Saleable Heavy Fuel Oil.

TABLE 6.1

SUMMARY OF ANNUAL* REDUCTION OF SULFUR DUE TO CHANGE IN FUEL SPECIFICATION

Specification	Region	**Refinery Own Fuel Consumption t	Saleable Heavy Fuel Oil (#4, #5 & #6) t	▶ Light Fuel Oil Products t	TOTAL metric tonne, t
1 #2 Fuel Oil and Lighter 0.3 wt.% S, max.	Atlantic	587	-10,032	3,948	-5,497
	Quebec	-694	18,378	6,818	24,502
	Ontario	2,803	3,485	8,155	14,443
	Western	-3	-192	3,433	3,238
	CANADA	2,693	11,639	22,354	36,686

* Annual = 325 days per year

** Including Heavy Fuel Oil & Light Fuel Oils (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene)

▶ Light Fuel Oil Products (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene): excluding refinery own consumption.

Table 6.2 Specification 2 (i):

HFO, 1.0 wt.% S, max.

- Total reduction of sulfur = 256,402 t/annum

  consists of (a) Refinery own fuel consumption = 14,561 t/annum

  (b) Saleable heavy fuel oil = 200,826 t/annum

  (c) Light fuel oils = 41,015 t/annum

- Regional sulfur reduction:

  Atlantic > Quebec > Western > Ontario

TABLE 6.2

SUMMARY OF ANNUAL* REDUCTION OF SULFUR DUE TO CHANGE IN FUEL SPECIFICATION

Specification	Region	**Refinery Own Fuel Consumption t	Saleable Heavy Fuel Oil (#4, #5 & #6) t	ᵽ Light Fuel Oil Products t	TOTAL metric tonne, t
2 (i) Heavy Fuel Oil (#4, #5 and #6) 1.0 wt.% S, max.	Atlantic	4,029	89,587	7,476	101,092
	Quebec	6,381	74,634	19,383	100,398
	Ontario	2,803	3,485	8,155	14,443
	Western	1,348	33,120	6,001	40,469
	CANADA	14,561	200,826	41,015	256,402

* Annual = 325 days per year

** Including Heavy Fuel Oil & Light Fuel Oils (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene)

ᵽ Light Fuel Oil Products (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene): excluding refinery own consumption.

Table 6.3 Specification 2 (ii):
HFO, 0.5 wt. % S, max.

. Total reduction of sulfur = 349,886 t/annum

consists of (a) Refinery own fuel consumption =
23,271 t/annum

(b) Saleable heavy fuel oil =
285,600 t/annum

(c) Light fuel oils =
41,015 t/annum

. Regional sulfur reduction :

Quebec > Atlantic > Western > Ontario

TABLE 6.3

SUMMARY OF ANNUAL* REDUCTION OF SULFUR DUE TO CHANGE IN FUEL SPECIFICATION

Specification	Region	**Refinery Own Fuel Consumption t	Saleable Heavy Fuel Oil (#4, #5 & #6) t	ᵖ Light Fuel Oil Products t	TOTAL metric tonne, t
2 (11) Heavy Fuel Oil (#4, #5 and #6) 0.5 wt.% S, max.	Atlantic	4,954	116,410	7,476	128,840
	Quebec	9,775	101,693	19,383	130,851
	Ontario	6,772	26,058	8,155	40,985
	Western	1,770	41,439	6,001	49,210
	CANADA	23,271	285,600	41,015	349,886

* Annual = 325 days per year

** Including Heavy Fuel Oil & Light Fuel Oils (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene)

ᵖ Light Fuel Oil Products (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene): excluding refinery own consumption.

Table 6.4 Impact of Spec. 2 on Sulfur of #2 Fuel Oil and Lighter

. Total reduction of sulfur in Light Fuel Oils including refinery own consumption = 41,119 t/annum

TABLE 6.4

SUMMARY OF ANNUAL* REDUCTION OF SULFUR IN LIGHT FUEL OILS DUE TO CHANGE IN FUEL SPECIFICATION

Item	Region	**Refinery Own Fuel Consumption t	Saleable Heavy Fuel Oil (#4, #5 & #6) t	ᵖ Light Fuel Oil Products t	TOTAL metric tonne, t
Impact of Specification 2 on sulfur of #2 Fuel Oil and Lighter	Atlantic	27	-	7,476	7,503
	Quebec	92	-	19,383	19,475
	Ontario	50	-	8,155	8,205
	Western	8	-	6,001	6,009
	CANADA	177	-	41,015	41,119

* Annual = 325 days per year

** Including Heavy Fuel Oil & Light Fuel Oils (#2 Fuel Oil,Diesel Fuel & Stove Oil/Kerosene)

ᵖ Light Fuel Oil Products (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene): excluding refinery own consumption.

Table 6.5 Combination of Spec. 1 and 2 (i)

. Total reduction of sulfur = 256,402 t/annum
Same as Spec. 2 (i)

Table 6.5 Combination of Spec. 1 and 2 (ii)

. Total reduction of sulfur = 349,886 t/annum
Same as Spec. 2 (ii)

TABLE 6.5

SUMMARY OF ANNUAL* REDUCTION OF SULFUR DUE TO CHANGE IN FUEL SPECIFICATION

Specification	Country	**Refinery Own Fuel Consumption t	Saleable Heavy Fuel Oil (#4, #5 & #6) t	ᵖ Light Fuel Oil Products t	TOTAL metric tonne, t
o Combination of 1 and 2 (i)	Canada	14,561	200,826	41,015	256,402
• Combination of 1 and 2 (ii)	Canada	23,271	285,600	41,015	349,886

o Same as Specification 2 (i)

• Same as Specification 2 (ii)

* Annual = 325 days per year

** Including Heavy Fuel Oil & Light Fuel Oils (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene)

ᵖ Light Fuel Oil Products (#2 Fuel Oil, Diesel Fuel & Stove Oil/Kerosene): excluding refinery own consumption.

6.2 SUMMARY OF DESIGN CAPACITY FOR ADDITIONAL PLANTS REQUIRED

Specification 1: LFO 0.3 wt. % S, max.

. No requirement for hydrodesulfurization unit

Table 6.6 Spec. 2 (i) : HFO, 1.0 wt. % S, max.

.	Vacuum Resid HDS	= 93,400	BPSD
.	Atmospheric Resid HDS	=45,400	BPSD
.	H_2 Plant	= 122	MMSCFD
.	Amine Plant	= 127	MMSCFD
.	Sulfur Recovery Plant	= 897	STPD

Table 6.6 Spec. 2 (ii) : HFO, 0.5 wt. % S, max.

.	Vacuum Resid HDS	= 179,400	BPSD
.	Atmospheric Resid HDS	= 45,000	BPSD
.	H_2 Plant	= 185	MMSCFD
.	Amine Plant	= 192	MMSCFD
.	Sulfur Recovery Plant	= 1,258	STPD

TABLE 6.6

SUMMARY OF DESIGN CAPACITY FOR ADDITIONAL PLANTS REQUIRED CANADA

Region	Crude Capacity BPCD	%	Case 2(i) 1.0 wt.% S in HFO					Case 2(ii) 0.5 wt.% S in HFO				
			Vac.Resid HDS BPSD	Atmos.Resid HDS BPSD	H_2 PLT.(97%) MMSCFD	Amine PLT. MMSCFD	Sulfur PLT. STPD	Vac.Resid HDS BPSD	Atmos.Resid HDS BPSD	H_2 PLT.(97%) MMSCFD	Amine PLT. MMSCFD	Sulfur PLT. STPD
Atlantic	448,900	19.0	30,900	45,400	104	67	506	47,400	45,000	135	77	606
Quebec	617,400	26.2	43,000	-	18	24	159	65,300	-	50	45	289
Ontario	758,200	32.1	-	-	-	-	-	41,000	-	-	28	95
Western	535,000	22.7	19,500	-	-	36	232	25,700	-	-	42	268
Canada	2,359,300	100.0	93,400	45,400	122	127	897	179,400	45,000	185	192	1,258

On Stream Factor = 0.89

6.3 SUMMARY OF INCREASED ANNUAL CRUDE OIL REQUIREMENTS

Table 6.7 Spec. 1: LFO 0.3 wt. % S, max.

- Total increased crude oil requirements = 1,087,926 Bbl/annum
- Regional increased crude oil requirements

  Quebec > Atlantic > Western > Ontario

Table 6.7 Spec. 2 (i): HFO 1.0 wt. % S, max.

- Total increased crude oil requirements = 7,178,829 Bbl/annum
- Regional increased crude oil requirements:

  Atlantic > Quebec > Western > Ontario

Table 6.7 Spec. 2 (ii) HFO 0.5 wt. % S, max.

- Total increased crude oil requirements = 12,980,722 Bbl/annum
- Regional increased crude oil requirements:

  Atlantic > Quebec > Ontario > Western

Table 6.7 Combination of Spec. 1 and 2 (i)

- Same as Spec. 2 (i)

Table 6.7 Combination of Spec. 1 and 2 (ii)

- Same as Spec. 2 (ii)

TABLE 6.7 SUMMARY OF INCREASED ANNUAL* CRUDE OIL REQUIREMENTS

CASE	SPECIFICATION	REGION				CANADA Bbl
		ATLANTIC Bbl	QUEBEC Bbl	ONTARIO Bbl	WESTERN Bbl	
1	#2 Fuel Oil & Lighter 0.3 wt. % S, max,	399,606	529,596	31,803	126,921	1,087,926
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	4,493,040	2,183,355	31,803	407,631	7,178,829
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max.	6,691,655	4,038,397	1,446,749	803,921	12,980,722
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	4,493,040	2,183,355	31,803	470,631	7,178,829
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	6,691,655	4,038,397	1,446,749	803,921	12,980,722

* Annual = 325 days per year

6.4 SUMMARY OF INCREASED ANNUAL CRUDE FEED REQUIREMENTS

Table 6.7 (a) Spec. 1: LFO 0.3 wt. % S, max

- Total increased crude feed requirements = 669,175 Bbl/annum
  or 106,390 M^3/annum
- Regional increased crude feed requirements:

Atlantic > Quebec > Western > Ontario

Table 6.7 (a) Spec. 2 (i): HFO 1.0 wt. % S, max.

- Total increased crude feed requirements = 1,607,125 Bbl/annum

or

= 255,513 M^3/annum

- Regional increased crude feed requirements:

Quebec > Atlantic > Western > Ontario

Table 6.7 (a) Spec. 2 (ii) : HFO 0.5 wt. % S, max.

- Total increased crude feed requirements = 4,375,475 Bbl/annum

or

= 695,644 M^3/annum

- Regional increased crude feed requirements:

Atlantic > Quebec > Ontario > Western

6.4 (Cont'd)

Table 6.7(a) Combination of Spec. 1 and 2(i)

. Same as Spec 2 (i)

Table 6.7(b) Combination of Spec. 1 and 2 (ii)

. Same as Spec 2 (ii)

TABLE 6.7 (a)

SUMMARY OF INCREASED ANNUAL* CRUDE FEED REQUIREMENTS CANADA

BASIS: 1979 Total crude oil requirement** = 113,407,000 M^3
or 713,307,000 Bbls (or 1,954,267 BPCD)

Case	Specification	Region				Canada
		Atlantic	Quebec	Ontario	Western	
		Bbl (M^3)	Bbl (M^3)	Bbl (M^3)	Bbl (M^3)	Bbl (M^3)
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max	340,925 (54,203)	231,725 (36,841)	24,700 (3,927)	72,150 (11,471)	699,500 (106,442)
2 (i)	HFO (#4, #5 & #6) 1.0 wt.% S, max.	483,275 (76,835)	725,725 (115,381)	24,700 (3,927)	373,750 (59,422)	1,607,450 (255,565)
2 (ii)	HFO (#4, #5 & #6) 0.5 wt.% S, max.	1,339,975 (213,039)	1,245,075 (197,951)	1,112,475 (176,869)	677,950 (107,785)	4,375,475 (695,644)
1 + 2 (i) o	Combination of case 1 and 2 (i)	483,275 (76,835)	725,725 (115,381)	24,700 (3,927)	373,750 (59,422)	1,607,450 (255,565)
1 + 2 (ii) •	Combination of case 1 and 2 (ii)	1,339,975 (213,039)	1,245,075 (197,951)	1,112,475 (176,869)	677,950 (107,785)	4,375,475 (695,644)

* Annual = 325 days per year

** Actual '79 requirements (statistics Canada) = 112,659,758 M^3

o Same as Case 2 (i)

• Same as Case 2 (ii)

6.5 SUMMARY OF INCREASED ANNUAL CRUDE OIL EQUIVALENT OF ENERGY REQUIREMENTS

Table 6.7 (b) Spec 1: LFO 0.3 wt. % S, max.

- Total increased crude oil equivalent of energy requirements = 418,751 Bbl/annum
- Regional increased crude oil equivalent of energy requirements:

  Quebec > Atlantic > Western > Ontario

Table 6.7 (b) Spec. 2 (i) HFO 1.0 wt. % S, max.

- Total increased crude oil requirements = 5,571,704 Bbl/annum
- Regional increased crude oil requirements:

  Atlantic > Quebec > Western > Ontario

Table 6.7 (b) Spec. 2 (ii) HFO 0.5 wt. % S, max.

- Total increased crude oil requirements = 8,605,247 Bbl/annum
- Regional increased crude oil requirements:

  Atlantic > Quebec > Ontario > Western

Table 6.7 (b) Combination of Spec. 1 to Spec. 2 (i)

- Same as Spec. 2 (i)

Table 6.7 (b) Combination of Spec. 1 to Spec. 2 (ii)

- Same as Spec. 2 (ii).

TABLE 6.7 (b) SUMMARY OF INCREASED ANNUAL* CRUDE OIL EQUIVALENT OF ENERGY REQUIREMENTS

CASE	SPECIFICATION	REGION				CANADA
		ATLANTIC Bbl	QUEBEC Bbl	ONTARIO Bbl	WESTERN Bbl	Bbl
1	# 2 Fuel Oil & Lighter 0.3 wt. % S, max.	58,681	297,871	7,428	54,771	418,751
2 (i)	HFO (#4,#5,#6) 1.0 wt. % S, max.	4,009,765	1,457,630	7,428	96,881	5,571,704
2 (ii)	HFO (#4,#5,#6) 0.5 wt. % S, max	5,351,680	2,793,322	334,274	125,971	8,605,247
1 + 2 (i)	Combination of Case 1 and Case 2 (i)	4,009,765	1,457,630	7,428	96,881	5,571,704
1 + 2 (ii)	Combination of Case 1 and Case 2 (ii)	5,351,680	2,793,322	334,274	125,971	8,605,247

* Annual = 325 days per year

6.6 SUMMARY OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OIL PRODUCTION DUE TO DESULFURIZATION

Table 6.8 Spec. 1 : LFO 0.3 wt. % S, max.

- Total decrease of HFO = 211 M.Bbl/annum
- Total decrease of LFO = 135 M.Bbl/annum

Table 6.8 Spec. 2 (i) : HFO 1.0 wt. % S, max.

- Total decrease of HFO = 1,162 M.Bbl/annum
- Total decrease of LFO = 190 M.Bbl/annum

Table 6.8 Spec. 2 (ii) : HFO 0.5 wt. % S, max.

- Total decrease of HFO = 3,614 M.Bbl/annum
- Total decrease of LFO = 190 M.Bbl/annum

Table 6.8 Combination of Spec. 1 and 2 (i)

- Same as Spec. 2 (i)

Table 6.8 Combination of Spec. 1 and 2 (ii)

- Same as Spec. 2 (ii)

TABLE 6.8

SUMMARY OF ANNUAL CHANGE OF HEAVY AND LIGHT FUEL OILS
PRODUCTION DUE TO DESULFURIZATION CANADA

No.	* Annual Change / Specification		Region				Total Change in Canada
			Atlantic	Quebec	Ontario	Western	
1	#2 Fuel Oil and Lighter 0.3% S, max.	HFO** M.Bbl	- 75	- 61	- 24	- 51	- 211
		LFO** M.Bbl	- 38	- 79	-	- 18	- 135
2	(i) HFO (#4, #5, #6) 1.0 wt.% S, max	HFO** M.Bbl	- 394	-497	- 24	-247	-1,162
		LFO** M.Bbl	- 38	-174	-	+ 22	- 190
	(ii) HFO (#4, #5, #6) 0.5 wt.% S, max.	HFO** M.Bbl	-1,153	-961	-985	-515	-3,614
		LFO** M.Bbl	- 38	-174	-	+ 22	- 190
4	o Combination of 1 and 2 (i)	HFO** M.Bbl	- 394	-497	- 24	-247	-1,162
		LFO** M.Bbl	- 38	-174	-	+ 22	- 190
	• Combination of 1 and 2 (ii)	HFO** M.Bbl	-1,153	-961	-985	-515	-3,614
		LFO** M.Bbl	- 38	-174	-	+ 22	- 190

* Annual = 325 days per year

** Including refinery own fuel consumption LFO denotes #2 Fuel Oil & Diesel Fuel & Stove Oil/Kerosene;

o Same as 2 (i)

• Same as 2 (ii)

6.7 SUMMARY OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA AND SULFUR PRODUCTION DUE TO RESIDS DESULFURIZATION

Table 6.9 Spec. 1 : LFO 0.3 wt. % S, max.

- No production because of no resids desulfurization

Table 6.9 Spec. 2 (i): HFO 1.0 wt. % S, max.

- Total increase of Fuel Gas = 2,107 M.FOEB/annum
- Total increase of Naphtha = 1,930 M.Bbl/annum
- Total increase of Sulfur =167,649 t/annum

Table 6.9 Spec. 2 (ii): HFO 0.5 wt. % S, max.

- Total increase of Fuel Gas = 3,794 M.FOEB/annum
- Total increase of Naphtha = 5,526 M.Bbl/annum
- Total increase of Sulfur =253,062 t/annum

Table 6.9 Combination of Spec. 1 and 2 (i)

- Same as Spec. 2 (i)

Table 6.9 Combination of Spec. 1 and 2 (ii)

- Same of Spec. 2 (ii)

TABLE 6.9

SUMMARY OF ANNUAL INCREASE OF FUEL GAS, NAPHTHA & SULFUR PRODUCTION DUE TO RESIDS DESULFURIZATION CANADA

No.	Specification	* Annual Increase	Region				Total Increase in Canada
			Atlantic	Quebec	Ontario	Western	
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	Fuel Gas(Gross) M.FOEB***	-	-	-	-	-
		Naphtha(Gross) M.Bbl	-	-	-	-	-
		Sulphur t **	-	-	-	-	-
2	(i) HFO (#4, #5, #6) 1 wt.% S, max.	Fuel Gas(Gross) M.FOEB***	+ 1,337	+ 529	-	+ 241	+ 2,107
		Naphtha(Gross) M.Bbl	+ 686	+ 879	-	+ 365	+ 1,930
		Sulphur t **	+ 98,459	+41,300	-	+27,890	+167,649
	(ii) HFO (#4, #5, #6) 0.5 wt.% S, max.	Fuel Gas(Gross) M.FOEB***	+ 1,640	+ 1,024	+ 743	+ 387	+ 3,794
		Naphtha(Gross) M.Bbl	+ 2,020	+ 1,623	+ 1,071	+ 812	+ 5,526
		Sulphur t **	+117,946	+76,100	+21,829	+37,187	+253,062
4	o Combination of 1 and 2 (i)	Fuel Gas(Gross) M.FOEB***	+ 1,337	+ 529	-	+ 241	+ 2,107
		Naphtha(Gross) M.Bbl	+ 686	+ 879	-	+ 365	+ 1,930
		Sulphur t **	+ 98,459	+41,300	-	+27,890	+167,649
	• Combination of 1 and 2 (ii)	Fuel Gas(Gross) M.FOEB***	+ 1,640	+ 1,024	+ 743	+ 387	+ 3,794
		Naphtha(Gross) M.Bbl	+ 2,020	+ 1,623	+ 1,071	+ 812	+ 5,526
		Sulphur t **	+117,946	+76,100	+21,829	+37,187	+253,062

* Annual = 325 days per year

** t = metric tonne, 2204.6 lbs.

*** FOEB = 6.3×10^6 BTU (H.V. of Fuel gas assumed = 600 BTU/SCF)

o Same as 2 (i)

• Same as 2 (ii)

6.8 SUMMARY OF INCREASED ANNUAL ENERGY REQUIREMENTS

Table 6.10 (a) Spec. 1: LFO, 0.3 wt. % S, max.

. Total increased energy requirements = 2,415,879 MMBTU/annum

(a) . Fuel = 261,215 FOEB
(b) . Electricity = 45,083 x 10^3 kW.h
(c) . Steam = 256,401 x 10^3 lbs.
(d) . Cooling Water =2,801 x 10^6 USG

. Regional increased energy requirements :

Quebec > Atlantic > Western > Ontario

Table 6.10 (b) Spec. 2 (i) : HFO, 1.0 wt. % S, max.

. Total increased energy requirements = 32,349,014 MMBTU/annum

(a) . Fuel = 2,359,847 FOEB
(b) . Electricity = 449,173 x 10^3 kW.h
(c) . Steam = 12,990,263 x 10^3 lbs
(d) . Cooling Water =30,945 x 10^6 USG

. Regional increased energy requirements:

Atlantic > Quebec > Western > Ontario

Table 6.10 (b) Spec. 2 (ii): HFO,0.5 wt. % S, max.

. Total increased energy requirements = 49,894,887 MMBTU/annum

(a) . Fuel 3,523,741 FOEB
(b) . Electricity =777,828 x 10^3 kW.h
(c) . Steam = 19,917 x 10^3 lbs.
(d) . Cooling Water=41,706 USG

. Regional increased energy required:

Atlantic > Quebec > Ontario > Western

TABLE 6.10 (a)

SUMMARY OF INCREASED ANNUAL ENERGY REQUIREMENTS

No.	Increased Energy / Specification		Increased Annual Energy Requirements				Total Fuel + Elec + Steam (10^6 BTU)
			Fuel FOEB (10^6 BTU)	Electricity 10^3 kW.h (10^6 BTU)	Steam 10^3 lb (10^6 BTU)	Cooling Water 10^6 USG	
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	Atlantic	41,094 (258,890)	5,469 (54,686)	27,872 (27,872)	266	(341,448)
		Quebec	193,248 (1,217,463)	32,339 (323,388)	181,000 (181,000)	2,106	(1,721,851)
		Ontario	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
		Western	24,503 (217,368)	5,434 (54,340)	38,816 (38,816)	361	(310,524)
		Total Canada	261,215 (1,708,651)	45,083 (450,827)	256,401 (256,401)	2,817	(2,415,879)

TABLE 6.10 (b)

SUMMARY OF INCREASED ANNUAL ENERGY REQUIREMENTS

No.	Increased Energy / Specification		Increased Annual Energy Requirements				Total Fuel + Elec + Steam (10^6 BTU)
			Fuel FOEB (10^6 BTU)	Electricity 10^3 10^6kW.h (10^6 BTU)	Steam 10^3 10^6 lb (10^6 BTU)	Cooling Water 10^6 USG	
2	(i) HFO (#4, #5, #6) 1.0 wt.% S, max.	Atlantic	1,633,840 (10,293,193)	232,894 (2,328,935)	10,709,695 (10,709,695)	19,357	(23,331,823)
		Quebec	652,804 (4,112,664)	172,975 (1,729,738)	2,583,471 (2,583,471)	10,485	(8,425,873)
		Ontario	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
		Western	70,833 (446,250)	41,463 (414,628)	- 311,616 (- 311,616)	1,019	(549,262)
		Total Canada	2,359,847 (14,867,037)	449,173 (4,491,714)	12,990,263 (12,990,263)	30,945	(32,349,014)
	(ii) HFO (#4, #5, #6) 0.5 wt.% S, max.	Atlantic	2,182,232 (13,748,060)	343,608 (3,436,075)	13,956,955 (13,956,955)	24,460	(31,141,090)
		Quebec	1,156,003 (7,282,818)	249,327 (2,493,264)	6,370,800 (6,370,800)	15,355	(16,146,882)
		Ontario	113,358 (714,153)	122,598 (1,225,979)	- 47,408 (- 47,408)	740	(1,892,724)
		Western	72,148 (454,534)	62,295 (622,947)	- 363,290 (- 363,290)	1,151	(714,191)
		Total Canada	3,523,741 (22,199,565)	777,828 (7,778,265)	19,917,057 (19,917,057)	41,706	(49,894,887)

6.8 (Cont'd)

Table 6.10 (c) Combination of Spec. 1 and 2 (i)

. Same as Spec. 2 (i)

Table 6.10 (c) Combination of Spec. 1 and 2 (ii)

. Same as Spec. 2(ii)

TABLE 6.10 (c)

SUMMARY OF INCREASED ANNUAL ENERGY REQUIREMENTS

No.	Specification \ Increased Energy		Increased Annual Energy Requirements				Total Fuel + Elec + Steam (10^6 BTU)
			Fuel FOEB (10^6 BTU)	Electricity 10^3 kW.h (10^6 BTU)	Steam 10^3 lb (10^6 BTU)	Cooling Water 10^6 USG	
4	o Combination of 1 and 2 (i)	Atlantic	1,633,840 (10,293,193)	232,894 (2,328,935)	10,709,695 (10,709,695)	19,357	(23,331,823)
		Quebec	652,804 (4,112,664)	172,975 (1,729,738)	2,583,471 (2,583,471)	10,485	(8,425,873)
		Ontario	2,370 (14,930)	1,841 (18,413)	8,713 (8,713)	84	(42,056)
		Western	70,833 (446,250)	41,463 (414,628)	- 311,616 (- 311,616)	1,019	(549,262)
		Total Canada	2,359,847 (14,867,037)	449,173 (4,491,714)	12,990,263 (12,990,263)	30,945	(32,349,014)
	• Combination of 1 and 2 (ii)	Atlantic	2,182,232 (13,748,060)	343,608 (3,436,075)	13,956,955 (13,956,955)	24,460	(31,141,090)
		Quebec	1,156,003 (7,282,818)	249,327 (2,493,264)	6,370,800 (6,370,800)	15,355	(16,146,882)
		Ontario	113,358 (714,153)	122,598 (1,225,979)	- 47,408 (- 47,408)	740	(1,892,724)
		Western	72,148 (454,534)	62,295 (622,947)	- 363,290 (- 363,290)	1,151	(714,191)
		Total Canada	3,523,741 (22,199,565)	777,828 (7,778,265)	19,917,057 (19,917,057)	41,706	(49,894,887)

o Same as Table 6.10 (b), 2 (i)

• Same as Table 6.10 (b), 2 (ii)

6.9 SUMMARY OF INCREASED ANNUAL COST OF OPERATING MATERIALS

Table 6.11 (a) Spec. 1: LFO, 0.3 wt. % S, max.

Total increased cost of operating materials =

$6.70 MM/annum

(a) . Energy = $6.23 MM/annum
(b) . Cooling Water = $0.21 MM/annum
(c) . Catalyst = $0.26 MM/annum

. Regional increased cost of operating materials:

Quebec > Atlantic > Western > Ontario

. Allocation of total increased cost of operating materials:

Energy > Catalyst > Cooling Water

Table 6.11 (b) Spec. 2 (i): HFO, 1.0 wt. % S, max.

. Total increased cost of operating materials =

$131.95 MM/annum

(a) . Energy = $119.97 MM/annum
(b) . Cooling Water = $ 2.22 MM/annum
(c) . Catalyst = $ 9.66 MM/annum
(d) . Chemicals = $ 0.10 MM/annum

. Regional increased cost of operating materials :

Atlantic > Quebec > Western > Ontario

. Allocation of total increased cost of operating materials:

Energy > Catalyst > Cooling Water > Chemicals

TABLE 6.11 (a)

SUMMARY OF INCREASED ANNUAL COST OF OPERATING MATERIALS

No.	Increased Cost (Annual) / Specification		Operating Materials				Total MM $
			Energy MM $	Cooling Water MM $	Catalyst MM $	Chemicals MM $	
1	#2 Fuel Oil and Lighter 0.3 wt.% S, max.	Atlantic	1.03	0.02	0.01	-	1.06
		Quebec	4.55	0.15	0.19	-	4.89
		Ontario	0.11	0.01	0.02	-	0.14
		Western	0.54	0.03	0.04	-	0.61
		Total Canada	6.23	0.21	0.26	-	6.70

6.9 (Cont'd)

Table 6.11 (b) Spec. 2 (ii): HFO, 0.5 wt. % S, max.

. Total increased cost of operating materials = $209.15 MM/annum

(a) . Energy =$182.36 MM/annum
(b) . Cooling Water =$ 3.00 MM/annum
(c) . Catalyst =$ 23.65 MM/annum
(d) . Chemicals =$ 0.14 MM/annum

. Regional increased cost of operating materials:

Atlantic > Quebec > Ontario > Western

. Allocation of total increase cost of operating materials:

Energy > Catalyst > Cooling Water > Chemicals

Table 6.11 (c) Combination of Spec. 1 and 2 (i)

. Total increase cost of operating materials = $132.06 MM/annum

(a) . Energy = $120.14 MM/annum
(b) . Cooling Water = $ 2.22 MM/annum
(c) . Catalyst = $ 9.60 MM/annum
(d) . Chemicals = $ 0.10 MM/annum

. Others same as Spec. 2 (i)

Table 6.11 (c) Combination of Spec. 1 and 2 (ii)

. Total increased cost of operating materials = $209.17 MM/annum

(a) . Energy = $182.38 MM/annum
(b) . Cooling Water = $ 3.00 MM/annum
(c) . Catalyst = $ 23.65 MM/annum
(d) . Chemical = $ 0.14 MM/annum

. Others same as Spec. 2 (ii)

TABLE 6.11 (b)

SUMMARY OF INCREASED ANNUAL COST OF OPERATING MATERIALS

No.	Increased Cost (Annual) / Specification		Operating Materials				Total
			Energy MM.$	Cooling Water MM.$	Catalyst MM.$	Chemicals MM.$	MM.$
2	(i) HFO (#4, #5, #6) 1.0 wt.% S, max.	Atlantic	93.22	1.39	5.86	0.05	100.52
		Quebec	26.27	0.75	2.49	0.02	29.53
		Ontario	0.11	0.01	0.02	-	0.14
		Western	0.37	0.07	1.29	0.03	1.76
		Total Canada	119.97	2.22	9.66	0.10	131.95
	(ii) HFO (#4, #5, #6) 0.5 wt.% S, max.	Atlantic	123.67	1.76	13.85	0.06	139.34
		Quebec	54.35	1.11	4.25	0.03	59.74
		Ontario	3.82	0.05	3.49	0.02	7.38
		Western	0.52	0.08	2.06	0.03	2.69
		Total Canada	182.36	3.00	23.65	0.14	209.15

TABLE 6.11 (c)

SUMMARY OF INCREASED ANNUAL COST OF OPERATING MATERIALS

No.	Specification / Increased Cost (Annual)		Operating Materials				Total
			Energy	Cooling Water	Catalyst	Chemicals	
			MM.$	MM.$	MM.$	MM.$	MM.$
4	Combination of 1 and 2 (i)	Atlantic	93.22	1.39	5.80	0.05	100.46
		Quebec	26.27	0.75	2.49	0.02	29.53
		Ontario	0.11	0.01	0.02	-	0.14
		Western	0.54	0.07	1.29	0.03	1.93
		Total Canada	120.14	2.22	9.60	0.10	132.06
	Combination of 1 and 2 (ii)	Atlantic	123.67	1.76	13.85	0.06	139.34
		Quebec	54.35	1.11	4.25	0.03	59.74
		Ontario	3.82	0.05	3.49	0.02	7.38
		Western	0.54	0.08	2.06	0.03	2.71
		Total Canada	182.38	3.00	23.65	0.14	209.17

6.10 SUMMARY OF CAPITAL INVESTMENT COSTS

Spec. 1: LFO, 0.3 wt. % S, max.

. No capital investments required for Canada.

Table 6.12 (a) Spec. 2 (i): HFO, 1.0 wt. % S, max.

. Total capital investments = $1,617,775,000 / annum

. Regional capital investments:

Western > Atlantic > Quebec

No capital investments required for Ontario.

Table 6.12 (b) Spec. 2 (ii): HFO, 0.5 wt. % S, max.

. Total capital investments = $2,130,860,000 /annum

. Regional capital investments:

Atlantic > Western > Quebec > Ontario

TABLE 6.12 (a)

All $ x 1000

SUMMARY OF CAPITAL INVESTMENT COSTS (1.0 wt. % S in HFO)

REGION	ATMOS. RESID. CAPITAL COST	VAC. RESID. CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULPHUR CAPITAL COST	TOTAL CAPITAL INVESTMENT
Atlantic	87,410	234,030	199,740	29,990	59,365*	610,535
Quebec	-	211,220	91,320	14,520	31,815	348,875
Ontario	-	-	-	-	-	-
Western	-	545,970	-	41,975	70,420	658,365
Total	87,410	991,220	291,060	86,485	161,600	1,617,775

* Including Tail Gas Clean Up

TABLE 6.12 (b)

SUMMARY OF CAPITAL INVESTMENT COSTS (0.5 WT. % S in HFO)

All $ x 1000

REGION	ATMOS, RESID. CAPITAL COST	VAC. RESID. CAPITAL COST	H2 PLANT CAPITAL COST	AMINE CAPITAL COST	SULPHUR CAPITAL COST	TOTAL CAPITAL INVESTMENT
Atlantic	87,840	287,870	229,250	33,320	71,835*	710,115
Quebec	-	241,500	104,930	25,820	41,520	413,770
Ontario	-	289,380	-	19,350	28,660	337,390
Western	-	551,120	-	43,675	74,790	669,585
Total	87,840	1,369,870	334,180	122,165	216,805	2,130,860

*Including Tail Gas Clean Up

6.11 SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "A"

Table 6.13 (a) Spec. 1: LFO, 0.3 wt. % S max.

- No capital investment required
- No capital charges and fixed operating costs required
- Additional crude feed cost:

  Atlantic > Quebec > Western > Ontario
- Increased energy cost:

  Quebec > Atlantic > Western > Ontario
- Allocation of variable operating costs:

  Crude > Energy
- Total increased operating costs

(i) based on 1979 crude price	=	$20.32	MM/annum
(ii) based on $20/Bbl crude price	=	$20.08	MM/annum
(iii) based on $25/Bbl crude price	=	$23.43	MM/annum
(iv) based on $30/Bbl crude price	=	$26.78	MM/annum
(v) based on $35/Bbl crude price	=	$30.13	MM/annum

- Increased operating costs:

  Quebec > Atlantic > Western > Ontario
- Total increased cost per barrel crude

(i) based on 1979 crude price	=	$0.032	/Bbl
(ii) based on $20/Bbl crude price	=	$0.032	/Bbl
(iii) based on $25/Bbl crude price	=	$0.037	/Bbl
(iv) based on $30/Bbl crude price	=	$0.042	/Bbl
(v) based on $35/Bbl crude price	=	$0.047	/Bbl

TABLE 6.13 (a)

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "A" CANADA

CASE: 0.3% LFO

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	314,278	511,185	605,223	525,642	1,956,328
I Capital Investment; MM $	N/A	N/A	N/A	N/A	N/A
II Capital and Operating Costs; MM $/Annum *					
1. Annual Capital Charges	N/A	N/A	N/A	N/A	N/A
2. Fixed Costs; MM $/Year					
a. Operating & Supervisory Personnel	N/A	N/A	N/A	N/A	N/A
b. Maintenance	N/A	N/A	N/A	N/A	N/A
c. General, Sales, Admin, Taxes, Insurance	N/A	N/A	N/A	N/A	N/A
3. Variable Costs:					
a. Cost of Additional Crude Feed					
(i) At 1979 Prices	7.90	4.37	0.36	0.99	13.62
(ii) At $ 20/bbl	6.82	4.63	0.49	1.44	13.38
(iii) At $ 25/bbl	8.52	5.79	0.62	1.80	16.73
(iv) At $ 30/bbl	10.23	6.95	0.74	2.16	20.08
(v) At $ 35/bbl	11.93	8.11	0.86	2.53	23.43
b. Energy Requirements	1.05	4.70	0.12	0.57	6.44
4. Catalysts and Chemicals	0.01	0.19	0.02	0.04	0.26
5. Credit for Sulphur	N/A	N/A	N/A	N/A	N/A
III Increased Annual*Operating Cost; MM $					
1. Case 3a (i)	8.96	9.26	0.50	1.60	20.32
2. Case 3a (ii)	7.88	9.52	0.63	2.05	20.08
3. Case 3a (iii)	9.58	10.68	0.76	2.41	23.43
4. Case 3a (iv)	11.29	11.84	0.88	2.77	26.78
5. Case 3a (v)	12.99	13.00	1.00	3.14	30.13
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	0.088	0.056	0.003	0.009	0.032
2. Case 3a (ii)	0.077	0.057	0.003	0.012	0.032
3. Case 3a (iii)	0.094	0.064	0.004	0.014	0.037
4. Case 3a (iv)	0.111	0.071	0.004	0.016	0.042
5. Case 3a (v)	0.127	0.078	0.005	0.018	0.047

* 325 Days

6.11 (Cont'd)

Table 6.13 (b) Spec. 2 (i) : HFO, 1.0 wt. % S, max.

- Total capital investment = $1,617.775 MM
- Allocation of increased capital and operating costs:
  - Capital Charges > Variable Costs > Fixed Costs > Catalyst and Chemicals
  - Credit for sulfur = $7.93 MM/annum at $31/L-T
- Fixed operating costs:

  Atlantic > Western > Quebec > Ontario
- Allocation of variable operating costs:

  Energy > Crude
- Additional crude cost:

  Quebec > Atlantic > Western > Ontario
- Increased energy cost:

  Atlantic > Quebec > Western > Ontario
- Total increased operating costs:

(i) based on 1979 crude price	=	$599.87 MM/annum
(ii) based on $20/Bbl crude	=	$601.62 MM/annum
(iii) based on $25/Bbl crude	=	$609.65 MM/annum
(iv) based on $30/Bbl crude	=	$617.69 MM/annum
(v) based on $35/Bbl crude	=	$625.70 MM/annum

- Increased operating costs:

  Atlantic > Western > Quebec > Ontario

  Total increased cost per barrel crude:

(i) based on 1979 crude price	=	$0.942 /Bbl
(ii) based on $20/Bbl crude price	=	$0.945 /Bbl
(iii) based on $25/Bbl crude price	=	$0.957 /Bbl
(iv) based on $30/Bbl crude price	=	$0.970 /Bbl
(v) based on $35/Bbl crude price	=	$0.963 /Bbl

TABLE 6.13 (b)

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "A" CANADA

CASE: 1.0ES HFO

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	314,716	512,705	605,223	526,570	1,959,214
I Capital Investment; MM $	610.535	348.875	N/A	658.365	1,617.775
II Capital and Operating Costs; MM $/Annum *					
1. Annual Capital Charges	152.63	87.22	N/A	164.59	404.44
2. Fixed Costs ; MM $/Year					
a. Operating & Supervisory Personnel	4.97	5.57	N/A	4.18	14.72
b. Maintenance	4.58	2.62	N/A	4.94	12.14
c. General, Sales, Admin, Taxes, Insurance	5.34	3.05	N/A	5.76	14.15
3. Variable Costs:					
a. Cost of Additional Crude Feed					
(i) At 1979 Prices	11.20	13.70	0.36	5.14	30.40
(ii) At $ 20/bbl	9.67	14.51	0.49	7.48	32.15
(iii) At $ 25/bbl	12.08	18.14	0.62	0.34	40.18
(iv) At $ 30/bbl	14.50	21.77	0.74	11.21	48.22
(v) At $ 35/bbl	16.91	25.40	0.84	13.08	56.23
b. Energy Requirements	94.61	27.02	0.12	0.44	122.19
4. Catalysts and Chemicals	5.91	2.51	0.02	1.32	9.76
5. Credit for Sulphur	(4.54)	(1.38)	N/A	(2.01)	(7.93)
III Increased Annual* Operating Cost; MM $					
1. Case 3a (i)	274.70	140.31	0.50	184.36	599.87
2. Case 3a (ii)	273.17	141.12	0.63	186.70	601.62
3. Case 3a (iii)	275.58	144.75	0.76	188.56	609.65
4. Case 3a (iv)	278.00	148.38	0.88	190.40	617.69
5. Case 3a (v)	280.41	152.01	0.98	192.30	625.70
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	2.686	0.842	0.003	1.078	0.942
2. Case 3a (ii)	2.671	0.847	0.003	1.092	0.945
3. Case 3a (iii)	2.694	0.869	0.004	1.103	0.957
4. Case 3a (iv)	2.718	0.890	0.004	1.114	0.970
5. Case 3a (v)	2.742	0.912	0.005	1.125	0.983

* 325 Days

6.11 (Cont'd)

Table 6.13 (c) Spec. 2 (ii): HFO, 0.5 wt. % S, max.

- Total capital investment = $2,130.86 MM
- Allocation of increased capital and operating costs:
  - Capital Charges > Variable Costs > Fixed Costs > Catalyst and Chemicals
  - Credit for sulfur = $11.09 MM/annum at $31 / L-T
  - Fixed operating costs:

    Atlantic > Western > Quebec > Ontario
  - Allocation of variable operating costs:

    Energy > Crude
  - Additional crude cost:

    Atlantic > Quebec > Ontario > Western
  - Increased energy cost:

    Atlantic > Quebec > Ontario > Western
  - Total increased operating costs
    - (i) based on 1979 crude price = $865.22 MM/annum
    - (ii) based on $20/Bbl crude price = $872.45 MM/annum
    - (iii) based on $25/Bbl crude price = $894.33 MM/annum
    - (iv) based on $30/Bbl crude price = $916.20 MM/annum
    - (v) based on $35/Bbl crude price = $938.09 MM/annum
  - Increased operating costs:

    Atlantic > Quebec > Western > Ontario
  - Total increased cost per barrel crude:
    - (i) based on 1979 crude price = $1.353 /Bbl
    - (ii) based on $20/Bbl crude price = $1.364 /Bbl
    - (iii) based on $25/Bbl crude price = $1.398 /Bbl
    - (iv) based on $30/Bbl crude price = $1.433 /Bbl
    - (v) based on $35/Bbl crude price = $1.467 /Bbl

TABLE 6.13 (c)

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "A" CANADA

CASE: 0.5%S HFO

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	317,352	514,303	608,570	527,506	1,967,731
I Capital Investment; MM $	710.115	413.770	337.39	669.585	2,130.86
II Capital and Operating Costs; MM $/Annum*					
1. Annual Capital Charges	177.53	103.44	84.35	167.39	532.71
2. Fixed Costs; MM $/Year					
a. Operating & Supervisory Personnel	4.97	5.57	4.78	4.18	19.50
b. Maintenance	5.33	3.10	2.53	5.02	15.98
c. General, Sales, Admin, Taxes, Insurance	6.21	3.62	2.95	5.86	18.64
3. Variable Costs:					
a. Cost of Additional Crude Feed					
(i) At 1979 Prices	31.06	23.51	16.39	9.32	80.28
(ii) At $ 20/bbl	26.80	24.90	22.25	13.56	87.51
(iii) At $ 25/bbl	33.50	31.13	27.81	16.95	109.39
(iv) At $ 30/bbl	40.20	37.35	33.37	20.34	131.26
(v) At $ 35/bbl	46.90	43.58	38.94	23.73	153.15
b. Energy Requirements	125.43	55.46	3.87	0.61	185.37
4. Catalysts and Chemicals	13.95	4.28	3.51	2.09	23.83
5. Credit for Sulphur	(5.43)	(2.51)	(0.82)	(2.33)	(11.09)
III Increased Annual* Operating Cost; MM $					
1. Case 3a (i)	359.05	196.47	117.56	192.14	865.22
2. Case 3a (ii)	354.79	197.86	123.42	196.38	872.45
3. Case 3a (iii)	361.49	204.09	128.98	199.77	894.33
4. Case 3a (iv)	368.19	210.31	134.54	203.16	961.20
5. Case 3a (v)	374.89	216.54	140.11	206.55	938.09
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	3.481	1.175	0.594	1.121	1.353
2. Case 3a (ii)	3.440	1.184	0.624	1.146	1.364
3. Case 3a (iii)	3.505	1.221	0.652	1.165	1.398
4. Case 3a (iv)	3.570	1.258	0.680	1.185	1.433
5. Case 3a (v)	3.635	1.295	0.708	1.205	1.467

* 325 Days

6.12 SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "B"

Table 6.14 (a) Spec.: 1: LFO 0.3 wt. % S, max.

- No capital investment required
- No capital charges and fixed operating costs required
- Cost of increased crude (feed + equivalent to energy):

  Quebec > Atlantic > Western > Ontario

- Total increased operating costs:

(i)	based on 1979 crude price	=	$21.93	MM/annum
(ii)	based on $20/Bbl crude price	=	$22.23	MM/annum
(iii)	based on $25/Bbl crude price	=	$27.68	MM/annum
(iv)	based on $30/Bbl crude price	=	$33.12	MM/annum
(v)	based on $35/Bbl crude price	=	$38.55	MM/annum

- Increased operating costs:

  Quebec > Atlantic > Western > Ontario

- Total increased cost per barrel crude :

(i)	based on 1979 crude price	=	$0.034/Bbl
(ii)	based on $20/Bbl crude price	=	$0.035/Bbl
(iii)	based on $25/Bbl crude price	=	$0.044/Bbl
(iv)	based on $30/Bbl crude price	=	$0.052/Bbl
(v)	based on $35/Bbl crude price	=	$0.061/Bbl

TABLE 6.14 (a)

CASE: 0.3 wt. % S in LFO

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "B" CANADA

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	314,278	511,185	605,223	525,642	1,956,328
I Capital Investment; MM.$	N/A	N/A	N/A	N/A	N/A
II Capital and Operating Costs; MM.$/Annum*					
1. Annual Capital Charges	N/A	N/A	N/A	N/A	N/A
2. Fixed Costs; MM $/Year					
a. Operating & Supervisory Personnel	N/A	N/A	N/A	N/A	N/A
b. Maintenance	N/A	N/A	N/A	N/A	N/A
c. General, Sales, Admin, Taxes, Insurance	N/A	N/A	N/A	N/A	N/A
3. Variable Costs:					
a. Cost of Increased Crude (Feed + Equi. to Energy)					
(i) At 1979 Prices	9.26	9.99	0.47	1.74	21.46
(ii) At $ 20/bbl	7.99	10.59	0.64	2.54	21.76
(iii) At $ 25/bbl	9.99	13.24	0.81	3.17	27.21
(iv) At $ 30/bbl	11.99	15.89	0.97	3.80	32.65
(v) At $ 35/bbl	13.98	18.53	1.12	4.45	38.08
b. Cooling Water	0.02	0.15	0.01	0.03	0.21
4. Catalysts and Chemicals	0.01	0.19	0.02	0.04	0.26
5. Credit for Sulphur	N/A	N/A	N/A	N/A	N/A
III Increased Annual* Operating Cost; MM.$					
1. Case 3a (i)	9.29	10.33	0.50	1.81	21.93
2. Case 3a (ii)	8.02	10.93	0.67	2.61	22.23
3. Case 3a (iii)	10.02	13.58	0.84	3.24	27.68
4. Case 3a (iv)	12.02	16.23	1.00	3.87	33.12
5. Case 3a (v)	14.01	18.87	1.15	4.52	38.55
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	0.091	0.062	0.003	0.011	0.034
2. Case 3a (ii)	0.079	0.066	0.003	0.015	0.035
3. Case 3a (iii)	0.098	0.082	0.004	0.019	0.044
4. Case 3a (iv)	0.118	0.098	0.005	0.023	0.052
5. Case 3a (v)	0.137	0.114	0.006	0.026	0.061

*325 Days

6.12 (Cont'd)

Table 6.14 (b) Spec. 2 (i): HFO 1.0 wt. % S, max.

- Total capital investment = $1,617.775 MM
- Allocation of increased capital and operating costs:
  - Capital Charges > Variable Costs > Fixed Costs > Catalyst and Chemicals
- Credit for sulfur = $7.93 MM/annum at $31/L-T
- Fixed operating costs:

  Atlantic > Western > Quebec > Ontario

- Increased crude cost: (feed + equivalent to energy)

  Atlantic > Quebec > Western > Ontario

- Total increased operating costs:

(i)	based on 1979 crude price	= $601.81	MM/annum
(ii)	based on $20/Bbl crude price	= $593.08	MM/annum
(iii)	based on $25/Bbl crude price	= $628.97	MM/annum
(iv)	based on $30/Bbl crude price	= $664.88	MM/annum
(v)	based on $35/Bbl crude price	= $700.76	MM/annum

- Increased operating costs:

  Atlantic > Western > Quebec > Ontario

- Total increased cost per barrel crude:

(i)	based on 1979 crude price	= $0.945	/Bbl
(ii)	based on $20/Bbl crude price	= $0.931	/Bbl
(iii)	based on $25/Bbl crude price	= $0.988	/Bbl
(iv)	based on $30/Bbl crude price	= $1.044	/Bbl
(v)	based on $35/Bbl crude price	= $1.100	/Bbl

TABLE 6.14 (b)

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "B" CANADA

CASE: 1.0 wt. % S in HFO

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	314,716	512,705	605,223	526,570	1,959,214
I Capital Investment; MM.$	610.535	348.875	N/A	658.365	1,617.775
II Capital and Operating Costs; MM.$/ Annum *					
1. Annual Capital Charges	152.63	87.72	N/A	164.59	404.44
2. Fixed Costs; MM $/Year					
a. Operating & Supervisory Personnel	4.97	5.57	N/A	4.18	14.72
b. Maintenance	4.58	2.62	N/A	4.94	12.14
c. General, Sales, Admin, Taxes, Insurance	5.34	3.05	N/A	5.76	14.15
3. Variable Costs:					
a. Cost of increased Crude (Feed + Equi. to Energy)					
(i) At 1979 Prices	104.15	41.22	0.47	6.47	152.31
(ii) At $ 20/bbl	89.86	43.66	0.64	9.42	143.58
(iii) At $ 25/bbl	112.32	54.58	0.81	11.76	179.47
(iv) At $ 30/bbl	134.79	65.50	0.97	14.12	215.38
(v) At $ 35/bbl	157.25	76.42	1.12	16.47	251.26
b. Cooling Water	1.39	0.75	0.01	0.07	2.22
4. Catalysts and Chemicals	5.91	2.51	0.02	1.32	9.76
5. Credit for Sulphur	(4.54)	(1.38)	N/A	(2.01)	(7.93)
III Increased Annual*Operating Cost; MM.$					
1. Case 3a (i)	274.93	141.56	0.50	185.32	601.81
2. Case 3a (ii)	260.14	144.00	0.67	188.27	593.08
3. Case 3a (iii)	282.60	154.92	0.84	190.61	628.97
4. Case 3a (iv)	305.07	165.84	1.00	192.97	664.88
5. Case 3a (v)	327.53	176.76	1.15	195.32	700.76
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	2.683	0.850	0.003	1.083	0.945
2. Case 3a (ii)	2.543	0.864	0.003	1.100	0.931
3. Case 3a (iii)	2.763	0.930	0.004	1.114	0.988
4. Case 3a (iv)	2.983	0.995	0.005	1.128	1.044
5. Case 3a (v)	3.202	1.061	0.006	1.141	1.100

* 325 Days

6.12 (Cont'd)

Table 6.14 (c) Spec. 2 (ii): HFO 0.5 wt. % S, max.

- Total capital investment = $2,130.860 MM
- Allocation of increased capital and operating costs:
  - Capital Charges > Variables Costs > Fixed Costs > Catalyst and Chemicals
- Credit for sulfur = $11.09 MM/annum at $31/L-T
- Fixed operating costs:

  Atlantic > Western > Quebec > Ontario
- Increased crude cost: (feed + equivalent to energy)

  Atlantic > Quebec > Ontario > Western
- Total increased operating costs:

(i) based on 1979 crude price = $866.29 MM/annum
(ii) based on $20/Bbl crude price = $862.19 MM/annum
(iii) based on $25/Bbl crude price = $927.09 MM/annum
(iv) based on $30/Bbl crude price = $591.99 MM/annum
(v) based on $35/Bbl crude price = $1056.91 MM/annum

- Increased operating costs:

  Atlantic > Quebec > Western > Ontario
- Total increased cost per barrel crude:

(i) based on 1979 crude price = $1.355 /Bbl
(ii) based on $20/Bbl crude price = $1.348 /Bbl
(iii) based on $25/Bbl crude price = $1.450 /Bbl
(iv) based on $30/Bbl crude price = $1.551 /Bbl
(v) based on $35/Bbl crude price = $1.652 /Bbl

TABLE 6.14 (c)

SUMMARY OF CAPITAL INVESTMENT AND INCREASED OPERATING COSTS "B" CANADA

CASE: 0.5 wt. % S in HFO

	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
Capacity, BPCD					
1. Base Case	313,229	510,472	605,147	525,420	1,954,268
2. New Crude Case	317,352	514,303	608,570	527,506	1,967,731
I Capital Investment; MM.$	710.115	413.770	337.39	669.585	2.130.860
II Capital and Operating Costs; MM.$/Annum *					
1. Annual Capital Charges	177.53	103.44	84.35	167.39	532.71
2. Fixed Costs; MM $/Year					
a. Operating & Supervisory Personnel	4.97	5.57	4.78	4.18	19.50
b. Maintenance	5.33	3.10	2.53	5.02	15.98
c. General, Sales, Admin, Taxes, Insurance	6.21	.3.62	2.95	5.86	18.64
3. Variable Costs:					
a. Cost of Increased Crude (Feed + Equi. to Energy)					
(i) At 1979 Prices	155.11	76.25	21.31	11.05	263.72
(ii) At $ 20/bbl	133.83	80.77	28.94	16.08	259.62
(iii) At $ 25/bbl	167.29	100.96	36.17	20.10	324.52
(iv) At $ 30/bbl	200.75	121.15	43.40	24.12	389.42
(v) At $ 35/bbl	234.21	141.35	50.64	28.14	454.34
b. Cooling Water	1.76	1.11	0.05	0.08	3.00
4. Catalysts and Chemicals	13.95	4.28	3.51	2.09	23.83
5. Credit for Sulphur	(5.43)	(2.51)	(0.82)	(2.33)	(11.09)
III Increased Annual* Operating Cost; MM.$					
1. Case 3a (i)	359.43	194.86	118.66	193.34	866.29
2. Case 3a (ii)	338.15	199.38	126.29	198.37	862.19
3. Case 3a (iii)	371.61	219.57	133.52	202.39	927.09
4. Case 3a (iv)	405.07	239.76	140.75	206.41	991.99
5. Case 3a (v)	438.53	259.96	147.99	210.43	1056.91
IV Increased Cost per Barrel of Crude (New Crude Case); $/Bbl					
1. Case 3a (i)	3.435	1.166	0.600	1.128	1.355
2. Case 3a (ii)	3.279	1.193	0.639	1.157	1.348
3. Case 3a (iii)	3.603	1.315	0.675	1.181	1.450
4. Case 3a (iv)	3.927	1.434	0.712	1.204	1.551
5. Case 3a (v)	4.252	1.555	0.748	1.227	1.652

* 325 Days

REFERENCES

Ref. 1 - Petroleum Refineries In Canada, December 1979, Energy, Mines and Resources Canada.

Ref. 2 - "Petroleum Refining. Technology and Economics" J.H. Gary and G.E. Handwerk, Marcel Dekker Inc. New York, 1975.

Ref. 3 - Refined Petroleum Products, Statistics Canada Catalogue Number 45-004, December 1979.

Ref. 4 - Oil Week, June 9, 1980.

Ref. 5 - Energy and Automotive Emissions, January 1980 pre-print: International Lead Zinc Research Organization, Inc., New York.

Ref. 6 - Evaluation of Residual Desulfurization Processes For Petroleum Refineries, P.S. Krishnamoorthy, SNC/FW Ltd., August 1977.

Ref. 7 - Information supplied by APCD Environment Canada, computer printouts "Fuel Information from Refinery 1979"

Ref. 8 - "Guide To Refinery Operating Costs", W.L. Nelson Third Edition, The Publishing Co., Tulsa, 1976.

Ref. 9 - Hydrocarbon Processes - Catalysts, Chemicals Gulf Research & Development Co., 1977.

Ref. 10 - Canadian Petroleum Refineries Atmospheric Emmissions Survey 1978 Pace Report No. 80-5, December 1980.

TERMS OF REFERENCE

INTRODUCTION

Canadian petroleum refineries process about 650 million barrels of crude oil into various grades of petroleum products. Some desulphurization of the crude oil via the hydrodesulphurization technique takes place, and about 22% of the sulphur is recovered as elemental sulphur. However, the major part of the sulphur in crude oil is emitted to the atmosphere as sulphur oxide.

There are about 900,000 tons of sulphur in the crude oils processed every year in Canada.

About 200,000 tons are recovered as elemental sulphur in sulphur plants and 700,000 tons of sulphur are emitted to the atmosphere (or 1.4 million tons of SO_2) after combustion of the petroleum products.

About 550,000 tons of sulphur are released by the combustion of the finished products and about 150,000 tons are emitted by using petroleum products as fuel at the refineries. It has been further estimated that about 420,000 tons of sulphur are distributed in the heavy fuel oils which are used as fuel in the refineries or marketed in Canada.

The study will investigate the effect of reducing the sulphur content of fuels as follows:

1. No. 2 fuel oils and lighter will be limited to a maximum sulphur content of 0.3 wt%.

2. All fuel oils heavier than No. 2 fuel oil will be limited to a maximum sulphur content of

   (a) 1.0 wt%
   (b) 0.5 wt%

3. Impact of item 2 on the sulphur contents of No. 2 fuel oil and lighter

4) Combination of items 1 and 2

STUDY

Information on individual refinery fuel products, fuel sulphur content and refinery fuel for 1979 will be provided by APCD. Environment Canada.

The 1979 basic data, as established above, will be adjusted to meet separately the levels of sulphur content of fuel oil as specified in the introduction. Refinery fuel oil needs are to follow these sulphur limits. The study will consider the following aspects.

1) Annual* reduction of sulphur caused by the changes in fuel specification; broken down for:

   a) own fuel consumption
   b) saleable heavy fuel oil production
   c) light fuel oils

2) Investment on new facilities at the petroleum refineries to meet each specified sulphur level as outlined in the Introduction for items 1 to 4 (incl.) This should include sulphur recovery facilities with a recovery efficiency of 99% minimum where the sulphur production is 100 TD or more. For sulphur production rates less than 100 TD recovery efficiency should be 97.5% at least.

3) Increased annual* crude oil requirements.

4) Increased annual* energy requirements specified for fuel** electricity**, steam** and cooling water.

5) Increased cost of operating materials such as energy sources, cooling water, catalyst, chemicals. Unit cost by contractor.

6) Increased annual* operating costs from:

   1. Capital cost, 25% on Investment
   2. Crude oil cost, $/BBL to range from
      a) cost prevailing at regions for 1979, mid summer
      b) other values of 20, 25, 30, 35
   3. Cost and volume of additional energy requirements by processing unit, detailed by Contractor.
   4. Fixed annual operating costs, determined by Contractor..

Operating personnel	- $/yr per man
Supervisory/Techn. Personnel	- 25% of operating employee costs
Maintenance	- 3% of Capital Cost
General, Sales, Administrative, Taxes, Insurance	- 3.5% of Capital Cost

.../3

7) Credit for Sulphur, price by Contractor

8) Capital cost figures for 1979 to be based upon Nelson Construction Index of midsummer 1979. Capital costs to be adjustable to other values of the Nelson Construction Index by Contractor's method. (Note: Environment Canada may wish to revise these cost data in the future.)

These above aspects to be backed up with adequate detailed costs and other related information leading to the above detailed derivations and to be reported.

*	annual	- 325 days per year
**	fuel	- 6.3 million BTU per Barrel
**	electricity	- 1 kwh - 10,000 BTU
**	steam	- 1 lb - 1,000 BTU

9) Report will use information available in

"Evaluation of Residual Desulphurization Process for Petroleum Refineries" by P.S. Krishnamoorthy, Contract No. 3887, August 1977, SNC/FW, Montreal, Quebec.

POOR

QUALITY

ORIGINAL